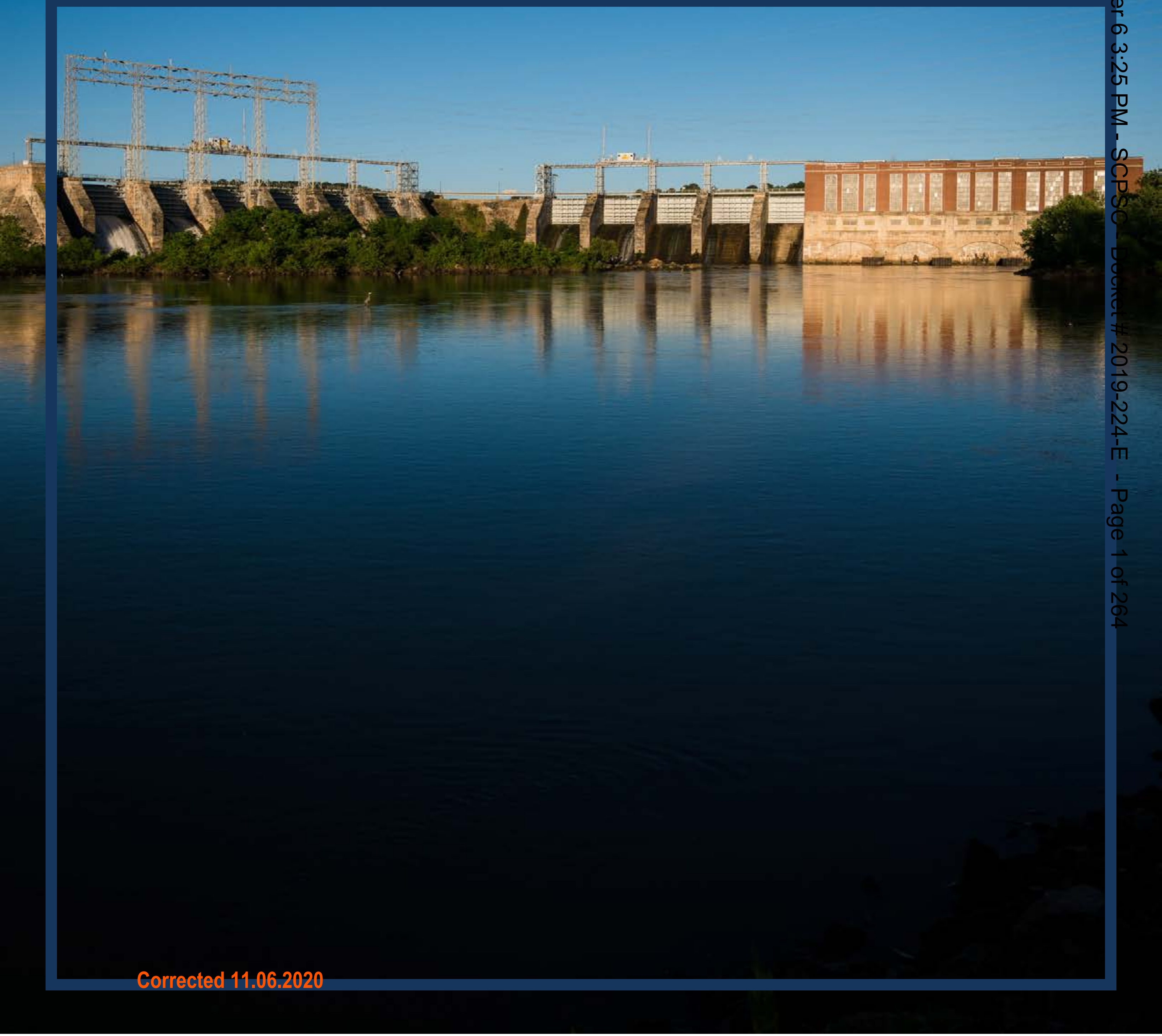
APPENDICES



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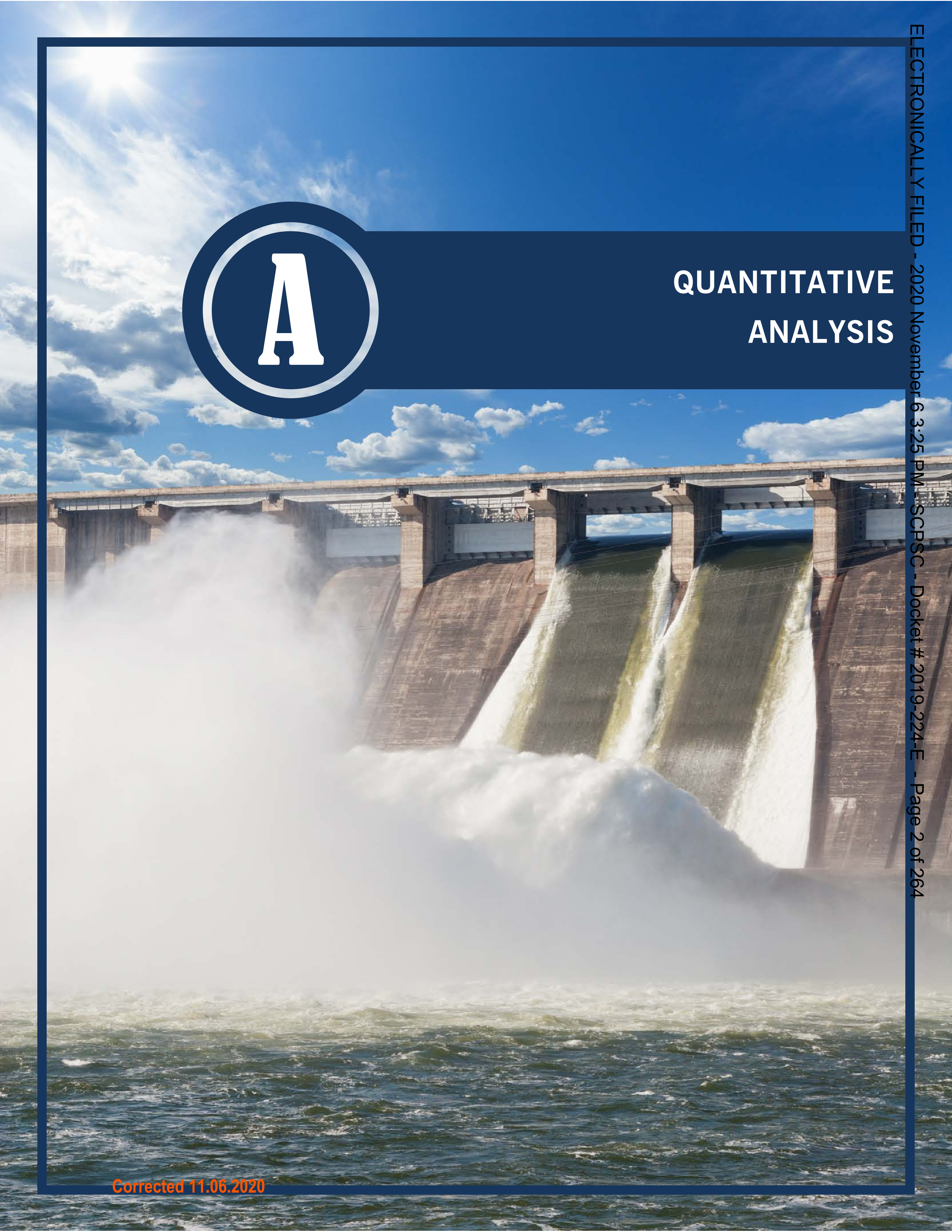

QUANTITATIVE ANALYSIS

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APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of the resource options available to meet customers' future energy needs. An evaluation of the economic retirement dates of DEC's coal plants helped establish the starting point for the quantitative analysis discussed in this appendix. Sensitivities on major inputs informed the development of multiple portfolios that were then evaluated under nine scenarios that varied combinations of fuel prices and CO_2 constraints. These portfolios were analyzed, identifying trade-offs between cost and carbon reductions, while considering opportunities and barriers to enable the portfolio's transition. Each of these plans account for the cost to customers, resource diversity, reliability and the long-term carbon intensity of the system and any of the six portfolios presented are potential pathways depending on future federal and state policies and technology advancements and cost trajectories.

The future resource needs were optimized for DEC and DEP independently. However, an additional case representative of jointly planning future capacity on a DEC/DEP combined system basis using the Base Case assumptions was also analyzed to demonstrate potential customer savings, if this option was available in the future.

OVERVIEW OF ANALYTICAL PROCESS

The analytical process consists of six steps:

1. Evaluate economic retirement dates of coal plants
2. Assess resource needs
3. Identify and screen resource options for further consideration
4. Develop base planning portfolio configurations and perform sensitivity analysis
5. Develop alternative portfolio configurations
6. Perform portfolio analysis over various scenarios

1. EVALUATE ECONOMIC SELECTION OF COAL PLANT RETIREMENT DATES

As discussed in Chapter 11, DEC conducted a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. This analysis identified the retirement dates used in the Base Planning with Carbon Policy and Base Planning without Carbon Policy for each of DEC's coal plants. In addition to the economic retirement analysis, the Company also determined the earliest practicable retirement dates for each coal asset. The "earliest practicable" retirement date portfolio is discussed later in this appendix.

Through the process detailed in Chapter 11, the following economic coal retirement dates were used in developing the base planning portfolios.

TABLE A-1
ECONOMIC RETIREMENT DATES OF DEC COAL PLANTS

	2019 IRP RETIREMENT YEAR (JAN 1)	2020 IRP MOST ECONOMIC RETIREMENT ANALYSIS RETIREMENT YEAR (JAN 1)
Allen 1	2025	2024
Allen 2	2025	2022
Allen 3	2025	2022
Allen 4	2028	2022
Allen 5	2028	2024
Cliffside 5	2033	2026
Marshall 1 – 4	2035	2035
Belews Creek 1 & 2	2039	2039
Cliffside 6	2049	2049

ALLEN STATION RETIREMENT DISCUSSION

The economic retirement analysis determined that the retirement of Allen station was economic by 2022; however, at least two of the five units must remain in service until completion of a new switch yard project by 2024.

Allen unit retirements in 2022 (YE2021) and 2024 (YE2023) and the associated new South Point switchyard, which is necessary to allow for the retirement of all five Allen units, will bring economic value to customers and further the clean energy goals held by the Company and stakeholders. As with all unit

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retirement dates in the IRP, this is not a commitment to retire the Allen units on this timeline but rather contains the Company's most recent estimate of retirement economics at the time of this filing. Official retirement will require final management approval with final retirement dates contingent upon the finalization of the supporting switchyard project and other operational considerations.

2. ASSESS RESOURCE NEEDS

The required load and generation resource balance needed to meet future customer demand was assessed as outlined below:

- **Customer peak demand and energy load forecast** – identified future customer aggregate demands to determine system peak demands and developed the corresponding energy load shape.

- **Existing supply-side resources** – summarized each existing generation resource's operating characteristics including unit capability, potential operational constraints and projected asset retirement dates.
- **Operating parameters** – determined operational requirements including target planning and operational reserve margins and other regulatory considerations.

Customer load growth, the expiration of purchased power contracts and additional asset retirements result in resource needs to meet energy and peak demands in the future. The following assumptions impacted the 2020 resource plan:

- **Peak Demand and Energy Growth -** The growth in winter customer peak demand after the impact of energy efficiency averaged 0.6% from 2021 through 2035. The forecasted compound annual growth rate for energy is 0.5% after the impacts of energy efficiency programs are included.

- **Planned Generation Uprates and Additions -**
    - Runner upgrades totaling 260 MW between 2020 and 2024 at Bad Creek Pumped-Storage Generating Station
    - Completion of the 402 MW Lincoln CT Unit #17 in 2024
    - Nuclear uprates at Oconee and Catawba totaling 57 MW

- **Reserve Margin** - A 17% minimum winter planning reserve margin for the planning horizon

3. IDENTIFY AND SCREEN RESOURCE OPTIONS FOR FURTHER CONSIDERATION

The IRP process evaluated EE, DSM and traditional and non-traditional supply-side options to meet customer energy and capacity needs. The Company developed EE and DSM projections based on existing EE/DSM program experience, the 2020 market potential study, input from its EE/DSM collaborative and cost-effectiveness screening for use in the IRP. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, nuclear, renewable, and energy storage). Supply-side options are initially screened based on the following attributes:

- Technical feasibility and commercial availability in the marketplace
- Compliance with all Federal and State requirements
- Long-run reliability
- Reasonableness of cost parameters

The Company compared the capacity size options and operational capabilities of each technology, with the most cost-effective options of each being selected for inclusion in the portfolio analysis phase. An overview of resources screened on technical basis and a levelized economic basis is discussed in Appendix G.

RESOURCE OPTIONS

ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both EE and DSM programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

The base planning assumptions for EE and DSM portfolios incorporates projected program adoption rates, and costs based on a combination of both internal company expectations, inclusive of current programs, and projections based on information from the 2020 market potential study. The program costs used for this analysis leveraged the Company's internal projections for the first five years and in the longer term, utilized the updated market potential study data incorporating the impacts of customer participation rates over the range of potential programs. Additionally, the Company included the impacts on energy and winter peak demand from the newly proposed IVVC program discussed in Appendix D.

Over the 15-year planning horizon, EE and DSM programs, including the new IVVC program discussed in Appendix D, are expected to provide over 1,200 MW of winter peak demand reduction in the base planning scenarios.

SUPPLY-SIDE

The following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

DISPATCHABLE (WINTER RATINGS)			
BASELOAD	PEAKING / INTERMEDIATE	STORAGE	RENEWABLE NON- DISPATCHABLE (WINTER RATINGS)
1,224 MW, 2x2x1 Advanced Combined Cycle (Duct Fired, No Inlet Chiller)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
684 MW, 12 Small Modular Reactor Nuclear Units (NuScale)		50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW Fixed-Tilt (FT) Solar PV
			75 MW Single Axis Tracking (SAT) Solar PV
			75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

4. DEVELOP BASE PLANNING PORTFOLIO CONFIGURATIONS AND PERFORM SENSITIVITY ANALYSIS

The step is broken down into three sections. The first section discusses the key variables in portfolio development and those considered in sensitivity and portfolio analysis. The second discusses the Base Planning portfolio development and results. The final section details the overall quantitative analysis of the individual sensitivity screening cases that were analyzed in the sensitivity analysis to inform the development of the alternative portfolios.

VARIABLES CONSIDERED IN SENSITIVITY & PORTFOLIO ANALYSIS

The Company uses base planning assumptions for the development of the base cases. However, the Company also conducted sensitivity analysis of various drivers using the expansion planning simulation modeling software, *System Optimizer* (SO). The expansion plans from these sensitivities produced by SO were then processed through the more detailed hourly production cost model, PROSYM to provide production costs for each of the expansion plans. The results of the sensitivity analysis were used to inform the development of the alternative portfolios presented in the IRP. Each of the base planning and alternative portfolios were analyzed under combinations of fuel and carbon tax trajectories in PROSYM in order to compare the Present Value of Revenue Requirements (PVRR) of each portfolio under the various scenarios, as well as, develop an estimate of average residential monthly bill impact of implementing the various portfolios under base planning assumptions. An overview of the key variable assumptions for the development of the base cases and for the Sensitivity and Scenario Analyses considered in both SO and PROSYM are outlined below:

LOAD FORECAST

DEC modeled the impacts of changes to the load forecast on the expansion plans. The Company based these sensitivities on the near-term growth and recession scenarios provided by Moody's Analytics. The impacts to the load forecast are summarized below:

TABLE A-2
LOAD FORECAST SENSITIVITY PARAMETERS

	LOW	BASE	HIGH
2035 Winter Peak Demand, MW	19,235	19,473	19,580
2035 Annual Energy, MWh	96,670,332	97,834,515	98,337,545

IMPACT OF POTENTIAL CARBON CONSTRAINTS

The base CO_2 price was developed to incentivize less carbon intensive resources on the path to net-zero carbon by 2050. Based on the earliest expected time to propose, pass and implement legislation or regulation the CO_2 price is set to begin in 2025. Ultimately, the CO_2 price will likely be dependent on many factors such as fuel and technology cost, tax incentives as well as pace of reduction goals.

In the 2019 IRP, the CO_2 price also started in 2025 at $5/ton and escalated at a rate of $3/ton per year, which incentivized CO_2 reductions of 60 to 70% by 2050 from a 2005 baseline. However, the price was not high enough to incentivize zero-emitting load-following resources (ZELFR) such as nuclear, hydrogen fueled generation or carbon capture and sequestration in lieu of natural gas generation prior to 2050.

In September 2019, after the filing of the 2019 IRP, Duke Energy announced an enterprise wide CO_2 reduction goal of at least 50% by 2030 and to be net-zero carbon by 2050. In addition to accelerating coal retirements, additional renewables and storage, there is a need for ZELFR technologies in 2035 to 2050 timeframe to facilitate the replacement of remaining coal generation and existing natural gas combined cycle generation as they meet their projected retirement dates. The company's analysis showed a CO_2 price starting at $5/ton in 2025 increasing at a rate of $5/ton per year incentivized ZELFR technology in the 2040 to 2050 timeframe, where increasing at a rate of $7/ton accelerated the selection of ZELFRs in the 2035 to 2040 timeframe. Both the $5 and $7/ton year price incentivize battery storage to meet a portion of new peaking need by 2030, additional renewables, accelerated coal retirements and limiting dispatch of carbon emitting generation.

There have been multiple federal legislative proposals that Duke has been tracking including:

- **Climate Leadership Council –** $40/ton escalating at 5% per year

- **CLEAN Futures Act –** A Clean Electricity Standard (CES) that incentivized similar reductions to \$5/ton escalating at \$7/ton per year

- **Energy Innovation and Carbon Dividend Act (H.R. 763) –** \$15/ton escalating at \$10 /ton per year

- **American Opportunity Carbon Free Act of 2019 (S. 1128) –** \$52/ton escalating at 8.5% per year

The Climate Leadership Council and CLEAN Futures Act each drive a similar pace of carbon reduction as the \$5/ton and \$7/ton per year carbon price trajectories. The higher CO_2 prices associated with H.R. 763 and S. 1128 would drive retirement of coal and gas generation at a faster pace which would accelerate the need for ZELFRs prior to 2035. However, the pace of CO_2 reduction would be limited by the amount of renewables and storage that could be interconnected in a given year, technological development and deployment of storage and ZELFRs technologies and the impact on customer rates.

In consideration of the mentioned legislative proposals and consistent with Duke Energy's CO_2 reduction goal, the Reference 2020 CO_2 price is \$5/ton starting in 2025 escalating at a rate of \$5/ton per year. This CO_2 price trajectory incentivizes the continued adoption of renewables, storage, accelerated coal retirements which supports a path to net-zero by 2050. When comparing alternative plans the inclusion of the CO_2 price in the overall project economics would be reflective of a carbon tax, and if excluded, would be reflective of a CO_2 mass cap or cap and trade with allowance allocations.

- **Base CO_2 Price –** \$5/ton in 2025 and escalating at \$5/ton annually applied to all stack carbon emissions.

- **High CO_2 Price –** \$5/ton in 2025 and escalating at \$7/ton annually applied to all stack carbon emissions.

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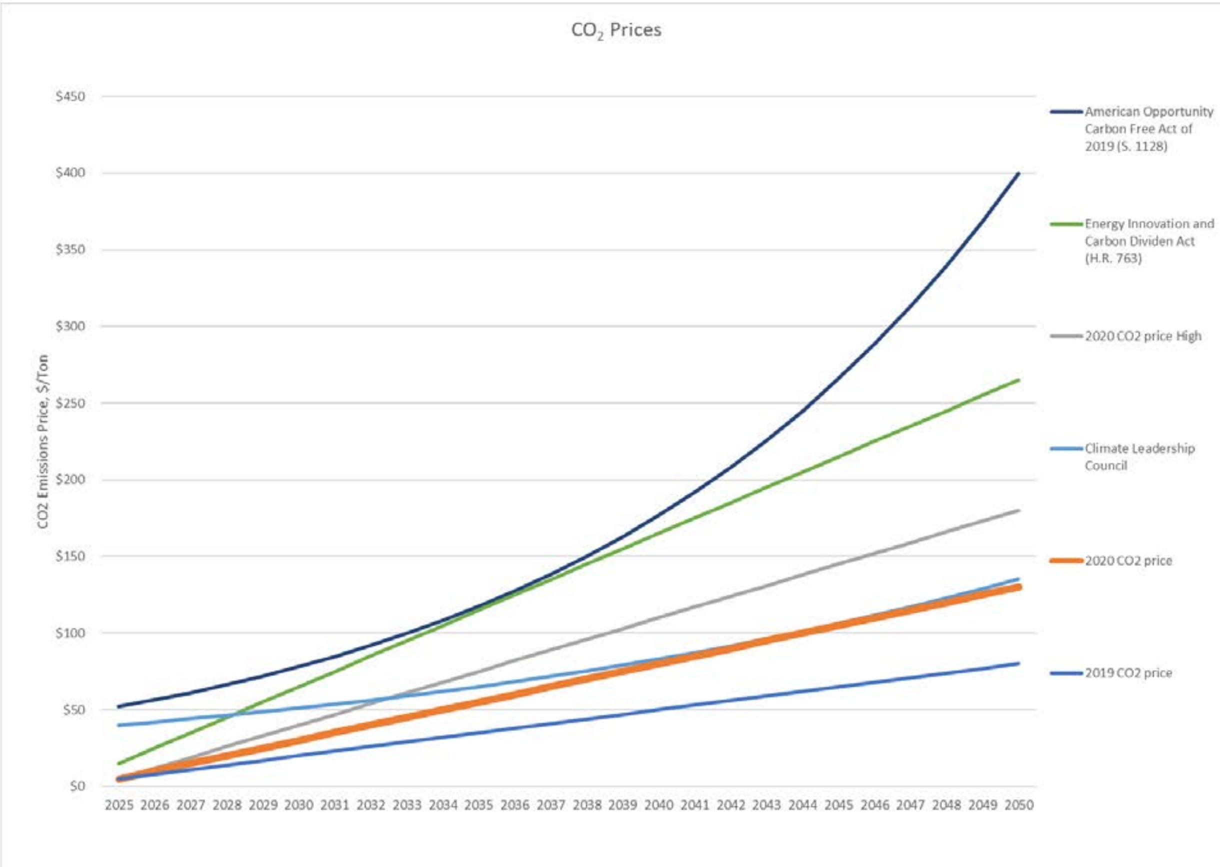
FIGURE A-1
COMPARISON OF CO_2 PRICES AND OTHER CO_2 REFERENCE PRICES



COAL PLANT RETIREMENT DATES

As described in Chapter 11, DEC evaluated the economic coal retirement dates for each coal plant. These dates were used in the base planning cases presented in the IRP. Additionally, DEC determined the earliest practicable retirement dates for each plant which contemplated the earliest date, setting aside normal economic considerations, that each coal plant could be retired but still giving consideration to the time it would take to place replacement resources into service. While the earliest practicable dates are technically feasible it would likely take supporting policy to effectuate such an aggressive retirement schedule, The complexities in the siting, permitting, construction and regulatory approvals for such a large amount of replacement resources in a short period of time would, in all likelihood, not be feasible without new supporting policy. This is emphasized when taking into

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account the fact that the combined DEC/DEP systems would simultaneously be retiring all coal units prior to 2030 or in the case of Cliffside unit 6 cease burning coal by 2030 limiting future operations to entirely natural gas in this scenario. The earliest practicable coal retirement dates and additional considerations are discussed later in this appendix.

ENERGY EFFICIENCY

DEC modeled the adoption rate and program cost associated with EE based on a combination of both internal company expectations and projections based on information from the 2020 market potential study. Table A-3 provides the base, enhanced, and low EE MW and MWh impacts by 2035 including measures added in 2020 and beyond.

TABLE A-3
EE SENSITIVITY ANALYSIS PARAMETERS

	LOW	BASE	HIGH
Winter Peak MW Reduced by 2035	283	377	424
MWh Reduced by 2035	2,089,358	2,785,811	3,125,222

DEMAND SIDE MANAGEMENT & IVVC

As discussed previously, DEC modeled the adoption rate and program cost associated with DSM based on a combination of both internal company expectations and projections based on information from the 2020 market potential study. Additionally, the Company included the newly developed IVVC program which provides a reduction to winter peak demand and overall energy consumption. Table A-4 provides the base, enhanced, and low DSM MW impacts by 2035 including measures added in 2020 and beyond. The base case was derived directly from the market potential study, while the enhanced case incorporated the market potential study and impacts associated with potential rate design demand response programs. The low case is simply a 25% reduction in adoption and cost impacts of DSM programs. The base IVVC program impacts are included in all three sensitivities.

TABLE A-4
DSM SENSITIVITY ANALYSIS PARAMETERS

	LOW	BASE	HIGH
Winter Peak MW Reduced by 2035	688	845	1,428

SOLAR, SOLAR + STORAGE, AND WIND GENERATION

Three levels of renewable generation were evaluated as discussed in Appendix E. Each level included varying assumptions regarding penetration of solar and solar plus storage, wind availability, and annual interconnection limits. As discussed further in Appendix E, the base case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond NC HB 589, including expected growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. The Base Case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

In addition to the base case, a high and low case were developed. These portfolios do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. Additionally, the high case also considers a combination of onshore and offshore wind as viable resources beginning in the 2030 timeframe. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed

In all three cases, incremental solar, solar plus storage, and onshore Carolinas wind were available for selection in the capacity expansion model. However, the annual amount of solar and solar plus

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storage that could be selected in each case was limited. Table A-5 details the differences between the inputs of the three renewable cases.

TABLE A-5
RENEWABLES SENSITIVITY ANALYSIS PARAMETERS

	LOW	BASE	HIGH
Forced Solar by 2035, Nameplate MW	2,463	3,475	5,802
Forced Central US Wind by 2035, MW	0	0	638
Forced Offshore Carolinas Wind by 2035, MW	0	0	138
Allowed Solar & Solar plus Storage Annually, MW/Year	225	300	500
Allowed Onshore Carolinas Wind Annually, MW/Year	150	150	150

Additionally, as described in Chapter 7, transmission upgrade costs associated with interconnecting these distributed resources was estimated. These costs were applied after the technology was selected and are included in the PVRR and average residential bill impacts discussed later in this appendix.

FUEL PRICES

DEC continues to rely on 10-year market purchases of natural gas and 5-years of market observations of coal prices before transitioning to fundamental fuel forecasts for development of the IRP.

- Natural Gas based on market prices from 2021 through 2030 transitioning to 100% fundamental by 2035.
- Coal based on market observations through 2024 transitioning to 100% fundamental by 2030.

In order to test the effects of changing fuel prices on resource selection and portfolio value, DEC developed high and low natural gas prices. By only changing natural gas prices, the impact on resource selection (CC vs CT vs Renewables) and dispatch (coal vs gas) can be evaluated. The natural gas prices evaluated in the 2020 IRP are shown in the chart below.

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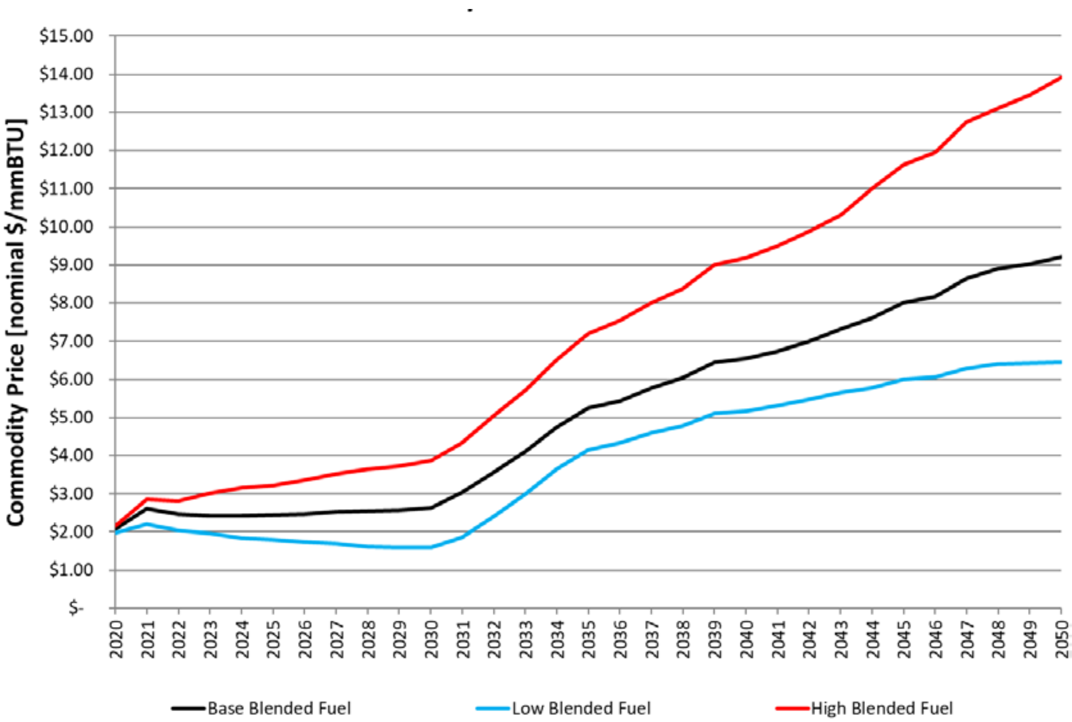
FIGURE A-2

NATURAL GAS PRICE SENSITIVITIES



The high and low natural gas price sensitivities were developed using a combination of high and low market and fundamental projections. The high and low market natural gas prices were developed using statistical analysis on market quotes to determine a 10th and 90th percentile probability. The high and low fundamental natural gas prices were derived using the base fundamental forecast and the EIA's 2020 Annual Energy Outlook (AEO) natural gas price forecasts from its Reference Case, Low Oil and Gas Supply Case, and High Oil and Gas Supply case.

CAPITAL COST SENSITIVITIES

Three capital cost sensitivities were performed. As discussed in Appendix G, most technologies include technology specific Technology Forecast Factors which were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO. More nascent technologies, such as battery storage and, to a lesser extent, PV solar, have relatively steep projected cost declines over time compared to more established technologies such as CCs and CTs. The first capital cost sensitivity evaluated the impact on the expansion plan of lower and higher reductions in solar PV costs as shown in Table A-6.

TABLE A-6

SOLAR & SOLAR + STORAGE CAPITAL COST SENSITIVITIES – PROJECTED PERCENT COST REDUCTION FROM 2020 TO 2029 BASED ON REAL 2020$

	LOW	BASE	HIGH
SOLAR PV % REDUCTION IN COST	-54%	-40%	-20%
SOLAR PV + STORAGE % REDUCTION IN COST	-61%	-46%	-26%

The second capital cost sensitivity evaluated the impact of reducing the asset life of a CT or CC from 35-years to 25-years. While the Company believes that natural gas is necessary for transitioning to a net-zero CO_2 emission future, this sensitivity considered the risk of new natural gas assets realizing an earlier than normal retirement.

The final capital cost sensitivity evaluated a reduction in battery storage costs to determine the impact on CT versus battery selection. Currently, the Company assumes that battery storage costs will decline by approximately 45% over the next decade. This sensitivity increases the cost decline to approximately 55%.

HIGH ENERGY REDUCTION FROM DEP'S DSDR PROGRAM

While the IRP base planning assumptions include energy reductions for DEP's Distribution System Demand Response Program, additional historical measurement and verification shows potential for further energy reduction from this program. The test year used for the IRP, 2018, provided approximately 100,000 MWhs of energy reduction by 2025, when the program would be fully implemented. Using a test year of 2017, the program could reduce energy by up to 400,000 MWhs, or 0.6% reduction in load for DEP, by the same timeframe. High level estimates suggest that this additional energy reduction, if realized, could result in approximately 140,000 ton of CO_2 reduction per year. While this additional energy reduction would further lower load on the DEP side, the reduction in load could also impact the energy transfer between utilities as part of the JDA. The additional reduction in energy will not impact the programs peak reduction capacity.

TECHNOLOGY ADVANCEMENTS

In some instances, certain technologies may not be considered "economic" within the planning horizon. However, these technologies may show significantly more value beyond the planning horizon particularly under strict carbon policies. Additionally, these resources may be required to achieve certain policy goals prior to the end of the planning horizon. For these reasons, the following technologies were evaluated in the 2020 IRP.

- **Small Modular Reactors (SMR) –** In order to achieve climate goals such as 70% CO_2 reduction by 2030 and net-zero carbon reduction by 2050, zero-emitting, load following resources (ZELFR) will be required. DEC evaluated SMRs as an example ZELFR within the planning horizon in several portfolios.

- **Offshore Wind –** While offshore wind was included in the Company's High Renewable sensitivity, several portfolios significantly increased the penetration of this resource to determine its impact on achieving 70% carbon reduction by 2030. This increase in penetration is reasonable, and is a likely outcome, if offshore wind is developed off the coast of the Carolinas.

- **Pumped Storage Hydro –** As non-dispatchable resources such as solar and wind become prevalent on the system, the need for storage increases to avoid curtailment and optimize utilization of these carbon free resources. As shown in the Company's Capacity Value of Battery Storage study, the value of short duration storage erodes rapidly as additional MW of similar storage durations are added. For this reason, pumped hydro storage that can provide 8 or more hours of charging and generating was considered in cases that included renewable energy beyond that found in the base case.

ENERGY STORAGE

150 MW of 4-hour Lithium ion batteries are included in all portfolios as placeholders for future assets to provide operational experience on the DEC system. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio.

In addition to these placeholders, solar coupled with storage was included in all of the various renewable cases and was available for selection in the capacity expansion model. Furthermore, as discussed in Chapter 11, the Company studied the impact of replacing CTs with 4-hour battery storage during various points over the planning horizon. Finally, as part of several of the portfolios presented later in this appendix, battery storage was viewed as a key resource in the presence of increasing renewable penetration and the efforts to achieve certain carbon reduction goals, as well as, in cases where new natural gas generation was not an available resource.

JOINT PLANNING

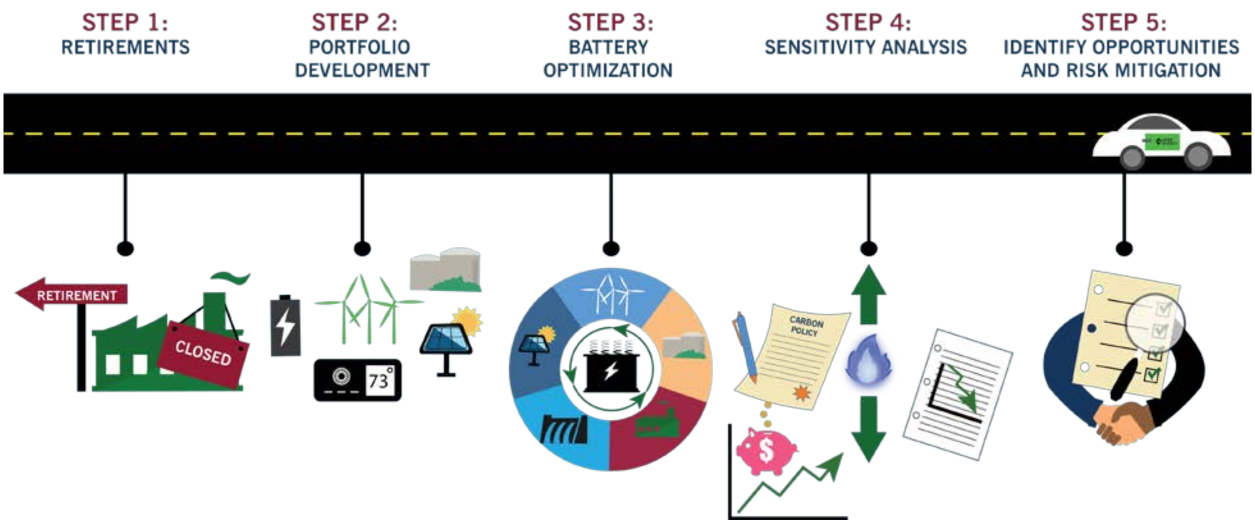
As required through the Joint Dispatch Agreement, DEC and DEP must plan to meet future capacity needs as individual utilities without the ability to share firm capacity. However, DEC performed a sensitivity assuming joint planning between DEC and DEP to investigate the benefits of shared resources and how new generation could be delayed. The Joint Planning analysis is discussed later in this appendix.

BASE CASE PORTFOLIO DEVELOPMENT AND RESULTS

The Base Cases utilize the company's current planning assumptions to determine least cost portfolios in scenarios with and without policy on carbon emissions from the electric generation fleet. These two (2) portfolios include the most economic retirement dates of the company's coal units, as discussed in Chapter 11. These portfolios utilize base planning assumptions for energy efficiency and demand response forecasts to reduce peak demand before incremental resource additions are evaluated. After the Base Case portfolios have been screened into the portfolio through the capacity expansion model, batteries were evaluated in a production cost model to optimize inclusion in the portfolios. Base Cases were then evaluated in sensitivity analysis to inform development of alternative portfolios. Below is a simplified process flow diagram for development of the base planning portfolios.

FIGURE A-3

SIMPLIFIED PROCESS FLOW DIAGRAM FOR BASE CASE PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS



BASE CASE WITHOUT CARBON POLICY

PORTFOLIO AND RESULTS DISCUSSION

The Base Case without Carbon Policy largely selects new natural gas generation to replace retiring coal generation. This portfolio adds nearly 4,300 MW of gas capacity to replace the retiring 3,700 MW of coal capacity and meet load growth. With the utility's current capacity position along with this IRP's lower, but still growing winter peak demand, the first traditional capacity addition is not needed until 2029, shortly after the retirement of Cliffside 5. There are no model-selected solar additions in this portfolio, which indicates that above the forecasted solar additions, the system would likely require additional economic support from either a carbon price or other supporting energy policy to continue adding renewable generation to the system. Through the battery optimization of this Base Cases, it was found that batteries were not economic within the IRP planning horizon.

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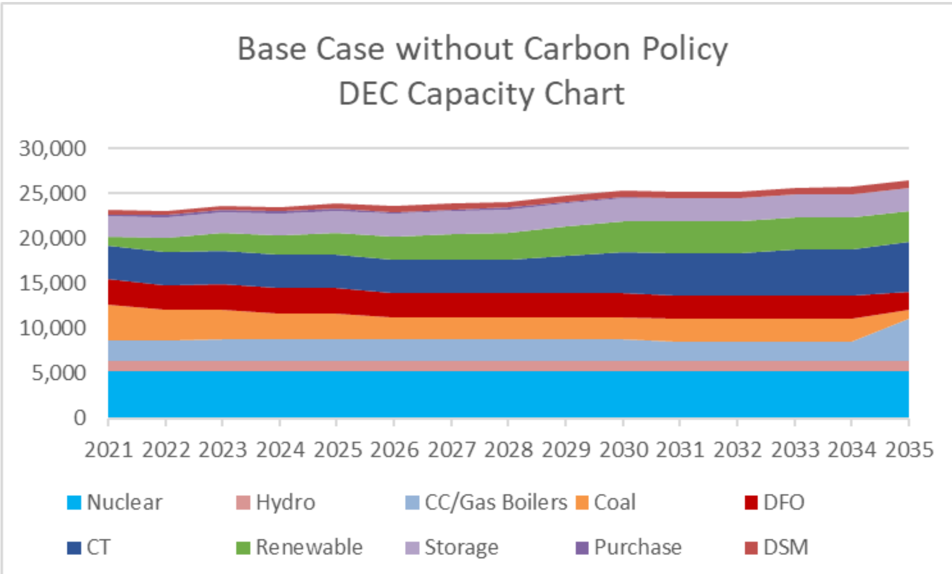
FIGURE A-4

DEC CAPACITY CHART - BASE CASE WITHOUT CARBON POLICY



BASE CASE WITH CARBON POLICY

PORTFOLIO AND RESULTS DISCUSSION

The Base Case developed under the assumption of future carbon policy results in a more diverse set of resource additions than its no carbon policy counterpart. This case adds 1,200 MW less natural gas generation by 2035 compared to the no carbon policy case, and instead adds 1,200 MW of additional solar and solar plus storage, and a small amount of wind, to meet energy and capacity need created by retiring coal. The addition of the carbon policy, in the form of a tax, drives the model-selected addition of these non-carbon emitting resources in this year's IRP. Even with the increased amount of intermittent resources and the steep decline in battery cost, this case found battery additions to be not economic within the IRP planning horizon. The results are due in part to the substantial amount of energy storage already on the DEC system in the form of the Company's pumped storage hydro fleet.

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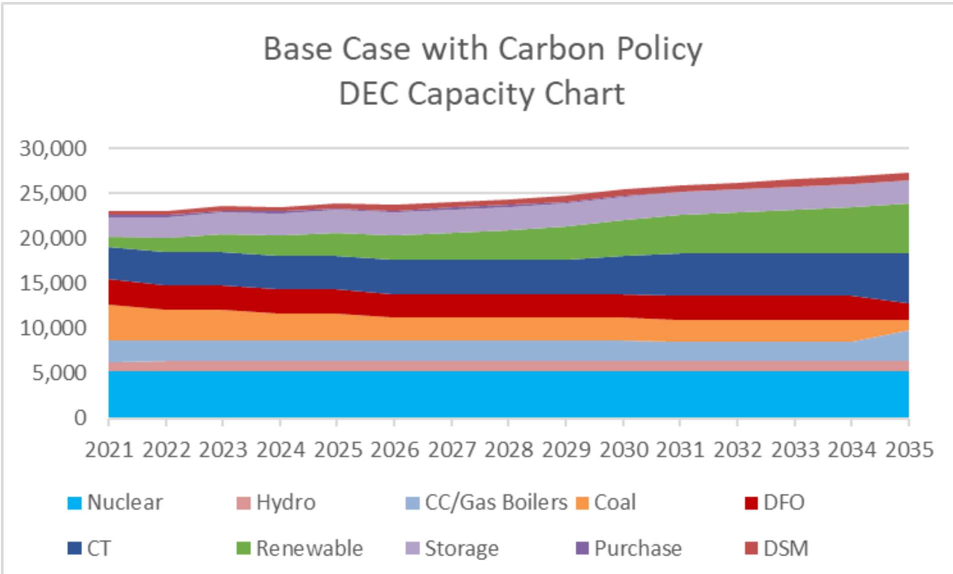
FIGURE A-5
DEC CAPACITY CHART - BASE CASE WITH CARBON POLICY



Below in Table A-7 is a comparison of the Base Case capacity expansion results.

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TABLE A-7

BASE CASE CAPACITY CHANGES WITHIN IRP PLANNING HORIZON

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITH CARBON POLICY
PORTFOLIO	A	B
Coal Retirements [MW]	3,754	3,754
Incremental Solar [MW]†	2,720	4,970
Incremental Onshore Wind [MW]†	0	150
Incremental Offshore Wind [MW]	0	0
Incremental SMR Capacity [MW]	0	0
Incremental Storage [MW]‡	351	595
Incremental Gas [MW]	4,276	3,052
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW]	1,222	1,222

†Combined forecasted and model-selected incremental additions by the end of 2035.

‡Includes Standalone Storage and Storage at Solar plus Storage sites

* Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour.

SENSITIVITY ANALYSIS RESULTS

Following the development of the Base Case portfolios, sensitivities were run to inform the development of the alternative portfolios. Table A-8 presents an overview of the year certain resources were selected by the capacity expansion model in each of sensitivities. Red indicates an earlier date than the Base Case with Carbon Policy, green indicates a later date than the Base Case with Carbon Policy, and orange indicates the resource was not selected during the planning horizon.

TABLE A-8

MATRIX OF FIRST SELECTION OF RESOURCES

	BASE		EE		DSM		LOAD		FUEL PRICE		RENEWABLES		SOLAR COST	
	W/ CO_2 POLICY	W/O CO_2 POLICY	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW
CT	2030	2030	2030	2035	2031	2031	2035	2035	2035	2035	2030	2035	N/A	2030
CC	2035	2035	2035	2029	2035	2026	2029	2031	2030	2029	2035	2029	2029	2035
Standalone Solar	2025	N/A	2025	2025	2025	2025	2025	2025	2025	2027	2027	2027	2028	2025
Solar Plus Storage	2029	N/A	2029	2030	2029	2029	2029	2030	2028	2032	2032	2030	N/A	2026
Onshore Wind	2035	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2034	N/A	2035	N/A	N/A	N/A

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Several observations from the sensitivity analysis are discussed below:

- **Timing of new natural gas generation –** The timing for the need of new natural gas generation does not change significantly across cases. New gas generation is accelerated when load is higher than the base (High Load and Low EE); other resources are available later or in lesser quantities (Low DSM, Low Renewables, High Solar Cost); or natural gas prices are lower than the base.

- **Type of new natural gas generation –** While CTs are selected as the first natural gas resource in the base case, in many other cases CCs are selected first. This likely signifies that there is little difference between the value of CTs and CCs as the first resource. This variation may also signify that DEC is somewhat energy limited. For instance, Low EE, Low Renewables, High Solar Cost all lead to a greater demand for non-energy limited resources earlier in the planning horizon. In those cases, CCs are selected first. In the cases of High EE, High Renewables, and Low Solar cost, the presence of solar and solar plus storage or the reduction in energy demand make energy from gas generation less critical, and CTs are selected before CCs. The resource mix in DEP also likely plays a role in the resource selection in DEC, and vice versa, as the Joint Dispatch Agreement allows for the transfer of energy between the two utilities. While the capacity expansion model cannot optimize capacity needs between the two utilities, it can optimize energy resources to take advantage of the JDA.

- **Solar Energy –** Solar energy could not have been accelerated prior to 2025 due to the 300 MW/year interconnection constraint placed on solar. However, solar plus storage could have been selected earlier than 2029; either in place of, or in conjunction with, standalone solar. Solar plus storage was accelerated in the case of higher fuel prices and lower solar costs. Solar plus storage was delayed if its energy or capacity was not needed or was met by other resources which occurred in most cases where CCs were selected prior to CTs.

- **Wind Energy –** Onshore Carolinas Wind was not selected in most cases. This likely signifies that in DEC, the resource is providing marginal value. In the base case, the capacity and energy from the wind resource helps meet a capacity need at the end of the planning horizon while providing valuable carbon free energy at the time of an increasing CO_2 tax. In most other cases, that value is limited as other resources such as EE, DSM, Solar, and natural gas are providing that capacity and energy value in front of onshore wind generation.

The following tables (Table A-9 and Table A-10) provide greater detail on the impacts of each sensitivity performed including impact to PVRR, CO_2 emissions by 2030 and 2035, and resource selection through 2035.

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TABLE A-9

PVRR ANALYSIS OF SENSITIVITIES THROUGH 2050, $ BILLIONS

	MASS CAP/CAP AND TRADE			CARBON TAX		
Base CO_2	$46.8			$55.1		
	PVRR	DELTA FROM BASE CASE WITH CARBON POLICY	PERCENT CHANGE FROM BASE CASE WITH CARBON POLICY	PVRR	DELTA FROM BASE CASE WITH CARBON POLICY	PERCENT CHANGE FROM BASE CASE WITH CARBON POLICY
Base CO_2 - High Load	$47.0	$0.2	0.4%	$55.4	$0.3	0.6%
Base CO_2 - Low Load	$44.3	-$2.5	-5.3%	$51.2	-$3.9	-7.1%
Base CO_2 - High Fuel	$52.8	$6.0	12.8%	$60.6	$5.5	10.0%
Base CO_2 - Low Fuel	$42.6	-$4.2	-9.0%	$51.5	-$3.5	-6.4%
Base CO_2 - High Renewables	$49.2	$2.4	5.1%	$55.9	$0.8	1.5%
Base CO_2- Low Renewables	$45.8	-$1.0	-2.2%	$54.5	-$0.6	-1.1%
Base CO_2 - High EE	$46.7	-$0.1	-0.2%	$54.8	-$0.2	-0.4%
Base CO_2 - Low EE	$46.7	-$0.1	-0.2%	$55.1	$0.0	0.0%
Base CO_2 - High DR	$47.0	$0.2	0.4%	$55.2	$0.2	0.3%
Base CO_2 - Low DR	$47.4	$0.6	1.2%	$56.2	$1.1	2.1%
Base CO_2 - High Renew Cost	$46.1	-$0.8	-1.6%	$55.5	$0.4	0.8%
Base CO_2 - Low Renew Cost	$46.1	-$0.7	-1.5%	$54.3	-$0.8	-1.4%
Base CO_2 - 25-Year Gas	$46.8	$0.0	0.0%	$55.6	$0.6	1.0%
Base CO_2 - Pumped Storage	$48.5	$1.7	3.6%	$56.3	$1.2	2.2%
Base CO_2 - DEP's High Energy DSDR	$46.8	$0.0	0.0%	$55.1	$0.0	0.0%
Min	$42.6	-$4.2	-9.0%	$51.2	-$3.9	-7.1%
Median	$46.8	$0.0	0.0%	$55.2	$0.2	0.3%
Max	$52.8	$6.0	12.8%	$60.6	$5.5	10.0%

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TABLE A-10

DEC SENSITIVITY ANALYSIS RESULTS

	BASE		EE		DSM		Load		Fuel Price		Renewables		Solar Cost	
	w/ CO_2 Policy	w/o CO_2 Policy	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
CO_2 Reduction by 2030 / 2035	59% / 62%	56% / 53%	60% / 62%	60% / 62%	60% / 62%	59% / 62%	61% / 63%	63% / 70%	60% / 59%	59% / 60%	61% / 66%	60% / 61%	59% / 61%	60% / 63%
2035 Winter Peak Demand	19,473	19,473	19,426	19,567	19,473	19,473	19,580	19,235	19,473	19,473	19,473	19,473	19,473	19,473
EE	377	377	424	283	377	377	377	377	377	377	377	377	377	377
DSM	845	845	845	845	1,428	688	845	845	845	845	845	845	845	845
Generation Added Over Planning Horizon (Nameplate Winter MW) †														
Gas Generation	3,052	4,276	3,052	3,362	3,052	4,733	3,362	2,905	3,052	3,362	3,052	3,362	3,672	3,362
Solar‡	5,410	3,493	5,410	5,368	5,410	5,410	5,410	5,368	5,518	5,068	6,796	4,500	4,393	5,668
Wind	150	0	0	0	0	0	0	0	0	0	150	0	0	0
Storage	558	351	558	539	558	558	558	539	576	501	631	329	351	614

† MWs represent availability on January 1, 2035.

‡Total Solar; Assumes 0.5% annual degradation.

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Several key takeaways from the sensitivity analysis include:

- Without a carbon policy, neither solar nor wind resources are economically selected.

- It appears that High EE is cost effective versus the base. Some of the value arises from avoiding onshore wind in the 2035 timeframe. The capacity and energy provided by the higher levels of EE is more valuable than the wind generation in the 2035 timeframe. There is executability risk with achieving these levels of energy efficiency. For this reason, these stretch targets were not included in the Base with and without Carbon Policy cases but were included in the aggressive CO_2 reduction portfolios. Future IRPs will include updated efficiency savings estimates and program cost forecasts as the Company continues to pursue delivering its portfolio of energy efficiency programs inclusive of working with stakeholders in the EE collaborative and industry experts to identify additional cost-effective programs.

- In cases where incremental capacity is needed, such as the High Load Forecast and Low EE and DSM sensitivities, gas generation is the preferred source of capacity versus solar plus storage or onshore wind generation.

- As expected, higher fuel prices, lower solar costs, and carbon policy drive increases in solar and solar plus storage resources.

- A review of the sensitivity PVRR analysis highlights that changes in fuel cost had the greatest impact on total PVRR. While the other variables influence incremental energy and resource selections, fuel presents the greatest cost opportunity and risk. The range of uncertainty supports continued diversity in fuel type and regional supply to minimize these risks.

Several other sensitivities investigating the value of Pumped Storage Hydro, a 25-year life for natural gas assets versus the base assumption of a 35-year life, and lower battery storage costs were also developed.

PUMPED STORAGE HYDRO

As discussed previously, as non-dispatchable renewable resources increase in number on the DEC system, longer duration energy storage will become critical to maintaining a reliable system. The sensitivity performed in this case was with Base Renewables along with DEC and DEP operating as separate utilities with current transmission capacity between the two utilities which limits the value of additions PSH. A scenario with higher renewable penetration and increased transmission capability between the two utilities would likely increase the value of PSH. The Company believes that under certain climate goals and carbon reduction policies, incremental PSH would be a valuable addition to the fleet.

25-YEAR NATURAL GAS ASSETS

There was little change to the expansion plan in the case where the asset life of natural gas CCs and CTs was reduced to 25-years from 35-years. In DEC, neither solar nor solar coupled with storage was accelerated to account for this change, however additional onshore wind generation was accelerated from just beyond the planning horizon to the 2033 timeframe. Timing of CC and CT generation did fluctuate with a CC accelerating from outside the planning horizon into the last year of the planning horizon, and a similar capacity of CTs slipping out of the planning horizon.

BATTERY STORAGE COSTS

In the Base Case with Carbon Policy, battery storage was determined not to be economic versus CT assets within the planning horizon. To test the impact of lower battery storage costs, the Company tested the PVRR cost effectiveness of a CT vs 4-hour Li-ion battery storage that was 15% lower cost than the original planning assumption. In DEC, the opportunity to replace a CT with battery storage occurs in 2028, 2030, and 2034. Even at the lower battery costs, the CT was the more economic option; however, by 2034 the battery became the more economic choice. Regardless of this exercise, as noted in Chapter 11, at the time new resources are needed on the DEC system, the Company will solicit bids to fill the resource gap as part of the CPCN process for new generation resources. Only then, will the true costs of competing technologies be fully known.

5. DEVELOPMENT OF ALTERNATIVE PORTFOLIO CONFIGURATIONS

While Base Case with and without Carbon Policy provide insight into the larger theme of the impact of carbon policies to drive reductions from a business as usual case, the company's approach in this IRP was to analyze multiple pathways that align to the of interest to stakeholders. These portfolios attempt to achieve desired outcomes of ceasing to burn coal in the Company's generation fleet, meeting aggressive carbon reductions goals, and in one scenario transition the fleet without the deployment of new gas generation. The work described in the previous section with respect to sensitivity analysis also helped inform the development of these pathways. While each of these pathways attempts to accomplish its own desired outcomes, the detailed examinations also help quantify tradeoffs of total costs of the implementation and operation of the pathway, pace of change and impact to the average residential monthly bill, dependency on technological development and deployment, and dependency on policy to enable the transition. This section highlights the additional portfolios analyzed and discusses some of the different requirements for each of the portfolios.

ALTERNATIVE PLANNING CASE RESULTS

EARLIEST PRACTICABLE COAL RETIREMENTS

EARLIEST PRACTICABLE COAL RETIREMENT ANALYSIS

In the 2020 IRP, the Company evaluated the potential factors that would restrict the Utility from retiring (or ceasing to burn coal at) the current coal fleet at their earliest practicable dates. To cease coal operations at nearly 7,000 MWs in DEC as earliest as practicable, this analysis suspends traditional "least cost" economic planning considerations, focusing on procurement and construction timelines for replacement capacity. The evaluation of these accelerations is often restricted by infrastructure to enable the replacements. Some of the most impactful factors contributing to earliest practical retirement dates are discussed below:

UTILITY PLANNING RESERVE MARGIN LENGTH

As with the most economic coal retirement analysis, the earliest practicable coal retirements also considered immediate planning reserve margin length of the utility to retire the capacity without replacement. To the extent possible, units were accelerated based on the available capacity length beyond the minimum planning reserve margin.

RETIRING COAL SITE TRANSMISSION

After retirements with excess planning capacity, the coal sites were considered for transmission grid impacts. With over 60-years of operations in the Carolinas, some the existing coal sites have become critical for reliability and stability of the grid. Retirement of these stations without replacement onsite often requires additional transmission projects which can further lead to delays in retirement of the coal fleet. To the extent possible, replacement generation in the Earliest Practicable case was located at the site of the retiring coal plants to avoid transmission projects which would further delay the retirement of these assets if replacement generation was built offsite.

INTERCONNECTION TO TRANSMISSION SYSTEM OF REPLACEMENT GENERATION

Also contributing to the ability to accelerate retirement of these assets is the need for infrastructure associated with new replacement generation sites, usually consisting of transmission interconnection, and possible requirements for gas and water infrastructure. The current process for getting through the interconnection queue could be significant given the size of the queue. Once interconnection studies are complete, depending on the outcome of those studies, transmission upgrades to interconnect the replacement capacity may then be required which can add years to the process of replacing existing generation. These timelines were accounted for when considering options for offsite replacement capacity.

LEVERAGING EXISTING INFRASTRUCTURE

Leveraging existing infrastructure rather than constructing new generation at greenfield sites can enable accelerated retirement of these assets. Siting replacement capacity generation at existing sites can alleviate the need for new land, water sources and reduce transmission upgrades that may be required to maintain grid stability should generation cease to exist at existing coal sites and leverage gas infrastructure already in place at many DEC coal sites. Where necessary, additional consideration was taken for incremental interstate gas pipeline to provide adequate gas supply to certain sites.

TABLE A-11

EARLIEST PRACTICABLE COAL RETIREMENT DATES OF DEC COAL PLANTS

	BASE CASE MOST ECONOMIC RETIREMENT YEAR (JAN 1)	EARLIEST PRACTICABLE COAL RETIRMENT YEAR (JAN 1)	CONSTRAINING FACTOR
Allen 2 – 4	2022	2022	Not Applicable – Retired with Capacity Length
Allen 1 & 5	2024	2024	Transmission project to enable retirement
Cliffside 5	2026	2026	Construction of onsite or offsite capacity
Marshall 1 – 4	2035	2028	Construction of onsite gas capacity
Belews Creek 1 & 2	2039	2029	Construction of onsite gas capacity, interstate pipeline
Cliffside 6	2049	2049*	*Conversion to 100% Gas in 2030, eliminating coal firing capabilities

FACTORS INFLUENCING EARLIEST PRACTICABLE COAL RETIREMENT DATES

As discussed, the primary consideration in the development of the "earliest practicable" coal retirement dates is the timeline to bring replacement resources into service. In DEC, with the exception of the coal units at Allen Station which can be retired without immediate capacity replacements, further coal retirements would necessitate replacement resources to be in service prior to retirement. Demand-side efforts identified in the IRP help to reduce the amount of resources needed to supply a growing customer base. However, the net demand and energy forecast after all demand-side initiatives is still positive. Hence any retirement of existing capacity resources creates a need for reliable replacement capacity to maintain overall system reliability. With respect to market purchases, it was assumed that in the aggregate expiring purchase contracts of existing traditional fossil resources and renewable energy resources where either extended or replaced in-kind through future RFP activities. This assumption further reduces the need for additional resources that would otherwise be required from the expiry of current purchase power contracts. Additional capacity purchases from neighboring balancing areas was not assumed eligible for replacement capacity in this analysis given the uncertain nature of the availability

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and cost of such potential purchases as well as the associated transmission requirements to bring in such purchases. More discussion on the ability and costs to increase transfer limits with neighboring service territories is outlined in Chapter 7.

Finally, the consideration of earliest practicable coal retirement dates assumes a continued aggressive growth in year-over-year renewable resources as depicted in the Base with Carbon Policy portfolio. After first considering the total impact of demand-side activities, market purchases and renewable additions it was determined that additional reliable capacity would be required in order to enable coal retirements while maintaining adequate planning reserves as discussed in Chapter 9. As a result, to arrive at the earliest practicable coal retirement dates requires minimizing the time to site, permit, construct and obtain regulatory approval for replacement capacity resources and supporting infrastructure. As previously mentioned, for the "earliest practicable" portfolio this time lag was assumed to be minimized by replacement resources being sited largely at the retiring coal facility locations to leverage existing land, water and transmission infrastructure.

PORTFOLIO AND RESULTS DISCUSSION

With the earliest practicable retirement dates established, the capacity expansion model was run to optimize the replacement capacity needs while adhering to the prescribed replacements required to enable retirements. This plan utilizes base renewable, energy efficiency and demand response projections, as the high integration rate and high energy efficiency and demand response program penetration may not be practicable. The plan adds a combined cycle and two (2) blocks of CTs in 2028, assumed to be at Belews Creek, and Marshall respectively, leveraging existing pipeline capacity, existing transmission interconnection, and avoiding transmission upgrades for retiring Marshall. The following year the plan adds a second combined cycle at Belews Creek and additional 1,400 MWs of CT at an undesignated location to meet capacity planning reserves in 2029 and retires the Belews Creek coal units. This case maintains coal operations at Cliffside 6 through 2029, when it is converted to 100% gas operations, to ensure flexibility and reliability of the system through this transition. While these earliest practicable dates are technically feasible, it would likely take supporting policy to effectuate given the complexities in the siting, permitting, construction and regulatory approval for such a large amount of resources in that period of time.

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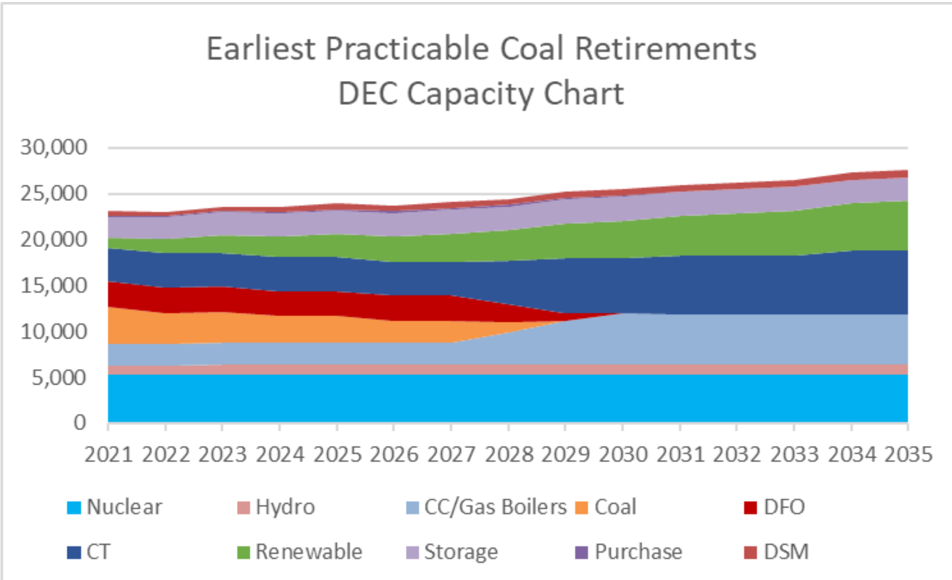
DUKE ENERGY CAROLINAS

FIGURE A-6

DEC CAPACITY CHART - EARLIEST PRACTICABLE COAL RETIREMENTS



70% CO_2 REDUCTION: HIGH WIND

The 70% CO_2 Reduction: High Wind portfolio outlines a pathway to reduce CO_2 system emissions by 70% by 2030, from a 2005 baseline, by tapping into offshore wind resources off the coast of the Carolinas. This scenario demonstrates the necessary investment requirements and procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio to reduce the overall emissions of the system. This plan highlights the benefits of bringing these resources into the company's service territory, and illustrates that the retirement of carbon intense resources, such as coal, alone is not enough to reach these lofty goals, but requires access to lower and carbon-free energy.

PORTFOLIO AND RESULTS DISCUSSION

The assumption of earliest practicable retirement dates underlies this plan to enable further reduction of carbon emissions by 2030. This plan also assumes high renewables, energy efficiency, and demand response projections, to provide carbon-free capacity and energy to further reduce CO_2 emission. Critically, the earliest practicable retirement dates, along with high levels of renewable penetration (4,000 MWs of solar as a combined system above the Base Case with Carbon Policy by 2035), is not enough to achieve 70% CO_2 reduction and additional carbon-free resources, such as offshore wind are needed.

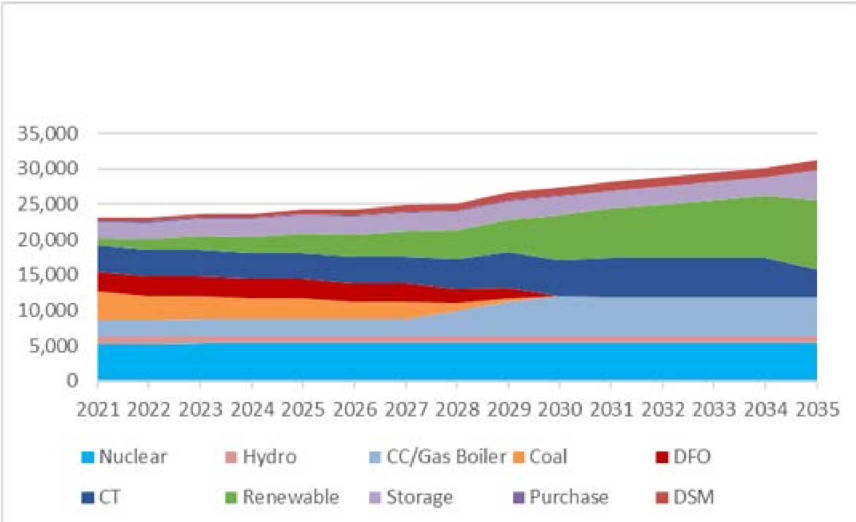
As with the previous case, gas generation will be required to enable these retirements and provide system flexibility and reliability while further reducing carbon emissions of the system.

This plan assumes 1,200 MWs of offshore wind are incorporated into the DEC service territory by 2030. To maintain enough capacity reserves before the offshore wind can be constructed and connected to the system, one Belews Creek unit's retirement is delayed one year from the earliest practicable retirement dates to 2030. Due to the geographical location of the offshore wind resource, significant transmission infrastructure will be required to deliver this energy to the DEC service territory. While offshore wind can provide bulk carbon-free energy, it does not provide one-for-one reliability equivalency. As an intermittent resource, the system will have to respond to variances in output from the offshore wind farm. Additionally, offshore wind is estimated to provide approximately 54% of its nameplate capacity towards meeting DEC's winter peak demand. While offshore wind capacity helps meet DEC's energy needs, the Company still requires traditional gas generation to accelerate coal retirements in this case and provide the needed capacity reserves to fulfill the Company's obligation to serve load.

While this portfolio achieves its intended outcome, it will likely require accelerated technological deployment enhancements and policy support to enable this pathway. While offshore wind is not necessarily a new technology, deployment in the US at large scale is yet to be demonstrated. The cost of the resource and getting the energy from coastal Carolinas to the load centers in the central part of the states will present implementation challenges. These challenges can be mitigated with effectively political and regulatory support and policy.

FIGURE A-7

DEC CAPACITY CHART - 70% CO_2 REDUCTION: HIGH WIND



70% CO_2 REDUCTION: HIGH SMR

The 70% CO_2 Reduction: SMR portfolio outlines a pathway to reduce CO_2 system emissions by 70% by 2030, from a 2005 baseline, by deploying advanced nuclear technologies by the end of this decade. This scenario demonstrates the necessary investment requirements and procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio to reduce the overall emissions of the system. This plan highlights the benefits of bringing advanced nuclear technologies into the Company's service territory, and illustrates that the retirement of carbon intense resources, such as coal, alone is not enough to reach these lofty goals. As with the 70% CO_2 Reduction: High Wind pathway, 70% CO_2 emissions reduction by 2030 requires access to diverse types of lower carbon and carbon-free energy.

PORTFOLIO AND RESULTS DISCUSSION

As with the previous 70% CO_2 Reduction case, the assumption of earliest practicable retirement dates underlies this plan, enabling this plan to further reduce carbon emissions by 2030. Similarly, in this case, earliest practicable retirement dates, along with high levels of renewable penetration (nearly 4,000 MWs of solar as a combined system above the Base Case with Carbon Policy by 2035), is not enough to achieve the desired carbon reduction goals and additional carbon free resources, such as small modular nuclear reactors (SMRs) are needed. As with the previous cases, gas generation is required to enable these retirements and provide system flexibility and reliability while further reducing carbon emissions of the system.

This plan assumes the deployment of a 684 MW SMR nuclear plant in DEC by 2030. This technology presents an opportunity for a carbon-free resource that can adjust output up and down to follow trends in load. The addition of SMR capacity in this case is relatively small compared to the DEC system nameplate capacity, but on an energy basis, these dispatchable resources provide a greater density of carbon-free energy as compared to their intermittent renewable counter parts. While the system benefits from these attributes, the ability to license, permit, and construct this emerging technology by 2030 presents a significant challenge. The first full-scale, commercial SMR project is slated for completion at the start of the next decade which is the same time period as the plant in this scenario. To complete a project of this magnitude would require a high level of coordination between state and federal regulators, and even with that assumption, the timeline is still challenged based on the current licensing and construction timeline required to bring this technology to DEC.

While this portfolio achieves its intended outcome, it will require highly effective coordination between the utility, regulatory bodies, and stakeholders to enable this pathway. While nuclear reactors are not a new technology, development and deployment of this design is yet to be demonstrated at large scale. Uncertainty in the project cost and timeline is another factor that will need to be understood before embarking on a groundbreaking project of this magnitude.

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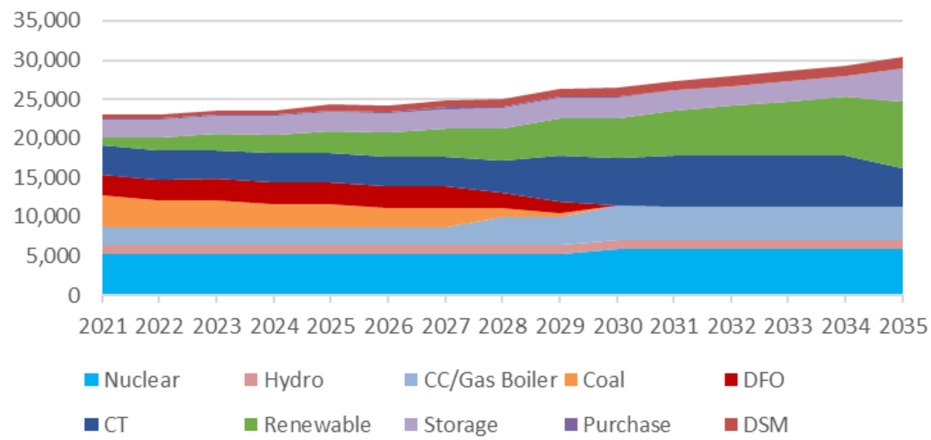
FIGURE A-8

DEC CAPACITY CHART - 70% CO_2 REDUCTION: HIGH SMR



NO NEW GAS GENERATION

There is growing interest from environmental advocates and Environmental, Social, and Corporate Governance (ESG) investors to understand the impacts of no longer relying on natural gas as a bridge fuel to a net-zero carbon future. This scenario explores a pathway, given the proper technological and policy advancements, to bridge the gap between now and the 2050 without building new gas generation. While gas generation is a mature, economical, and reliable resource, the reliance on natural gas as a bridge fuel has been challenged due to its continued reliance on fossil fuels and risks of standing these assets. More discussion about the shortening of the book life of new gas assets and utilizing existing gas infrastructure in a net-zero carbon future were discussed earlier in this appendix and in Chapter 16. To evaluate the cost and operability of the system without gas as a transition fuel, this pathway assumes no new gas generation projects and meets the remaining capacity and energy needs of the DEC system with existing and emerging zero-carbon emitting resources, including solar, storage, wind and SMRs.

PORTFOLIO AND RESULTS DISCUSSION

In a scenario, where economical gas generation additions, other than the development of Lincoln County CT #17, are eliminated, and firm winter capacity remains the binding constraint, the system must rely on the existing portfolio until existing technologies, such as batteries, can be built up on the system and emerging technologies become available, before retiring units in the current fleet. In order to allow

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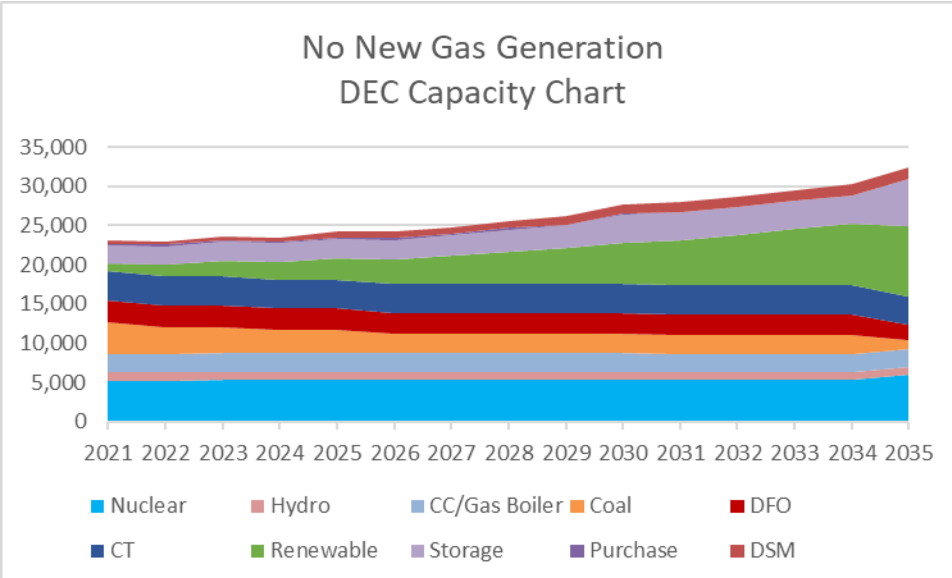
technologies to reach maturity and decline in price, the most economic coal retirement dates were used in this scenario. This coal capacity, with a secure fuel source and ability to match generation output with demand, will provide the needed capacity until the nascent technologies needed in the mix can be implemented throughout the systems at scale.

In DEC, leveraging high energy efficiency and demand response, and retaining coal capacity through its most economic life, the first capacity need appears upon the retirement of 2,000 MWs at Marshall in 2035. With this capacity length, DEC has more favorable timelines to allow for development of long lead time projects. In this case, with a high penetration of intermittent renewable energy resources, the benefit of additional energy storage rises. While batteries are quickly establishing themselves as assets to a generation fleet, the ability to move bulk energy at a pumped hydro station presents a unique opportunity. New pumped storage, with storage capacity up to twice the duration of current batteries on the market, is implemented in this case to provide 1,600 MWs of long-duration storage, to balance the system and optimize energy costs. When Marshall is retired, there is also a need for energy production. In this plan an SMR is added to the DEC portfolio in 2035. With the ability to wait for these technologies to mature, both operationally and economically, the DEC system benefits from adding this SMR capacity late in the IRP window, providing dispatchable and carbon-free energy.

Within the IRP planning window, the utility can leverage its current capacity length, implementing high levels of EE and DR, and lean on existing resources to bridge the gap without relying on new gas generation. However, soon after the planning window, additional resources begin retiring which will pose additional new challenges in meeting energy and capacity needs until more zero-emitting, load following resources can be deployed.

FIGURE A-9

DEC CAPACITY CHART - NO NEW GAS GENERATION



Below, Tables A-12 and A-13 illustrate the changes to system capacity in the IRP planning horizon for the Base Cases and Alternative Portfolios:

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TABLE A-12

BASE CASE AND ALTERNATIVE PORTFOLIO CAPACITY CHANGES WITHIN IRP PLANNING HORIZON

	BASE WITHOUT CARBON POLICY	BASE WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
PORTFOLIO	A	B	C	D	E	F
Coal Retirements [MW]	3,754	3,754	5,974	5,974	5,974	5,974
Incremental Solar [MW]	2,720	4,970	4,970	7,478	7,478	7,478
Incremental Onshore Wind [MW]	0	150	0	1,101	1,101	1,401
Incremental Offshore Wind [MW]	0	0	0	1,338	138	138
Incremental SMR Capacity [MW]	0	0	0	0	684	684
Incremental Storage [MW]ǂ	351	595	595	2,404	2,404	2,406
Incremental Gas [MW]	4,276	3,052	5,647	4,276	3,966	0
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW]*	1,222	1,222	1,222	1,853	1,853	1,853

†Combined forecasted and model-selected incremental additions by the end of 2035.

ǂIncludes Standalone Storage, Storage at Solar plus Storage sites, and Pumped Storage Hydro.

*Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour.

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TABLE A-13

COAL UNIT RETIREMENTS BY PORTFOLIO

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITHOUT CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: SMR	NO NEW GAS GENERATION
Allen 1 & 5	2024	2024	2024	2024	2024	2024
Allen 2-4	2022	2022	2022	2022	2022	2022
Cliffside 5	2026	2026	2026	2026	2026	2026
Cliffside 6	2049	2049	2049*	2049*	2049*	2049*
Belews Creek 1	2039	2039	2029	2030**	2030**	2039
Belews Creek 2	2039	2039	2029	2029	2029	2039
Marshall 1-4	2035	2035	2028	2028	2028	2035

* Cliffside 6 assumed to be 100% gas fired in all alternate portfolios starting in 2030.

**Delayed from Earliest Practicable Coal Retirement Dates for integration of offshore wind/SMR by 2030.

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6. PERFORM PORTFOLIO ANALYSIS OVER VARIOUS SCENARIOS.

PORTFOLIO PVRR ANALYSIS

Each of the six pathways identified in the portfolio development analysis were evaluated in more detail with an hourly production cost model (PROSYM) under future fuel price and CO_2 scenarios to determine the robustness of each portfolio under varying fuel and carbon futures. The run matrix for the nine scenarios is illustrated in Table A-14 below.

TABLE A-14
PORTFOLIO ANALYSIS RUN MATRIX

	NO CO_2	BASE CO_2	HIGH CO_2
Low Fuel			
Base Fuel			
High Fuel			

The PROSYM model provided the system production costs for each portfolio under the scenarios illustrated above. The model included DEC's non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEP, and as such, the model optimized both DEC and DEP and provided total system (DEC + DEP) production costs. The PROSYM results were separated to reflect system production costs that were solely attributed to DEC to account for the impacts of the JDA. The DEC specific system production costs were then added to the DEC specific capital costs for each portfolio to develop the total PVRR for each portfolio under the given fuel price and CO_2 conditions. The results of this total cost analysis, excluding the explicit cost of the carbon tax to customers (as if the carbon policy were applied as a Cap and Trade program with allowances), is summarized in Table A-15 below.

TABLE A-15

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$51.5	$52.3	$52.5	$60.3	$58.0	$60.4
High CO_2-Base Fuel	$46.2	$47.5	$47.1	$56.3	$53.9	$56.5
High CO_2-Low Fuel	$42.4	$43.9	$43.5	$53.4	$51.1	$53.8
Base CO_2-High Fuel	$50.6	$51.2	$52.2	$60.1	$57.6	$59.8
Base CO_2-Base Fuel	$45.8	$46.8	$46.8	$56.1	$53.6	$56.0
Base CO_2-Low Fuel	$42.0	$43.4	$43.1	$53.2	$50.7	$53.2
No CO_2-High Fuel	$49.3	$49.4	$51.2	$59.5	$56.6	$58.3
No CO_2-Base Fuel	$44.4	$44.9	$45.8	$55.5	$52.6	$54.6
No CO_2-Low Fuel	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7

Min	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Median	$45.8	$46.8	$46.8	$56.1	$53.6	$56.0
Max	$51.5	$52.3	$52.5	$60.3	$58.0	$60.4

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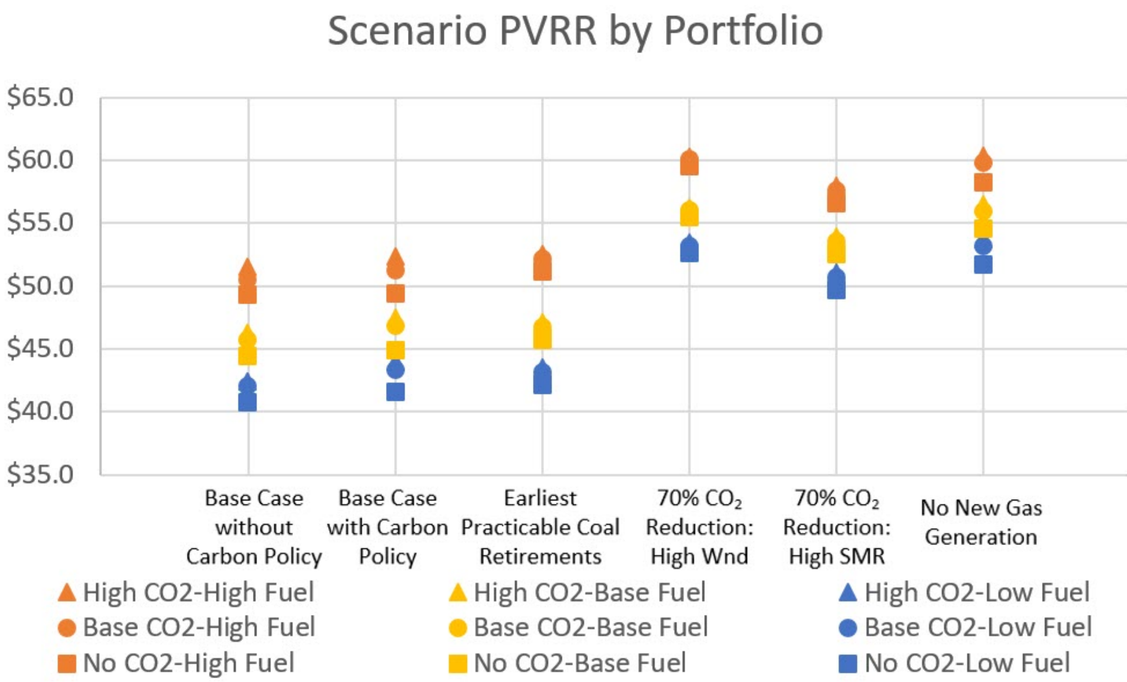
FIGURE A-10

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS



As seen in Figure A-10 above, each portfolio, when excluding the cost of carbon, have relatively tightly dispersed total PVRR costs, with results coalescing around the natural gas price rather than the underlying carbon price. The plans most affected by the variance in natural gas prices is the Base Case without Carbon Policy, which relies almost exclusively on new gas generation to meet future energy needs. As carbon policy, restrictions on resources, and carbon reduction goals grow, the cost of the plans generally rise, but the dispersion of variance relative to fuel prices shrinks. This is expected, as those plans shift away from natural gas and are naturally less sensitivity to fluctuations in gas price. While the 70% CO_2 reduction and No New Gas Generation cases are less sensitive to gas prices, they are overall more expensive plans, as a result of the costs to add more expensive resources with lower Effective Load Carrying Capabilities (ELCC) and energy output as well as the transmission needed to enable these resources.

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DUKE ENERGY CAROLINAS

Shown summarized in Table A-16 and Figure A-11 below are the results of the same total cost analysis as above, but now including the explicit cost of the carbon tax to customers (as if the carbon policy were applied as tax on carbon emission).

TABLE A-16

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$65.9	$64.0	$63.8	$68.3	$65.4	$68.4
High CO_2-Base Fuel	$59.8	$58.5	$58.3	$64.2	$61.3	$64.0
High CO_2-Low Fuel	$55.8	$54.9	$54.7	$61.3	$58.4	$61.1
Base CO_2-High Fuel	$61.8	$60.4	$60.5	$66.0	$63.1	$65.9
Base CO_2-Base Fuel	$55.9	$55.1	$55.0	$61.9	$59.0	$61.6
Base CO_2-Low Fuel	$51.9	$51.4	$51.4	$59.1	$56.2	$58.7
No CO_2-High Fuel	$49.3	$49.4	$51.2	$59.5	$56.6	$58.3
No CO_2-Base Fuel	$44.4	$44.9	$45.8	$55.5	$52.6	$54.6
No CO_2-Low Fuel	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Min	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Median	$55.8	$54.9	$54.7	$61.3	$58.4	$61.1
Max	$65.9	$64.0	$63.8	$68.3	$65.4	$68.4

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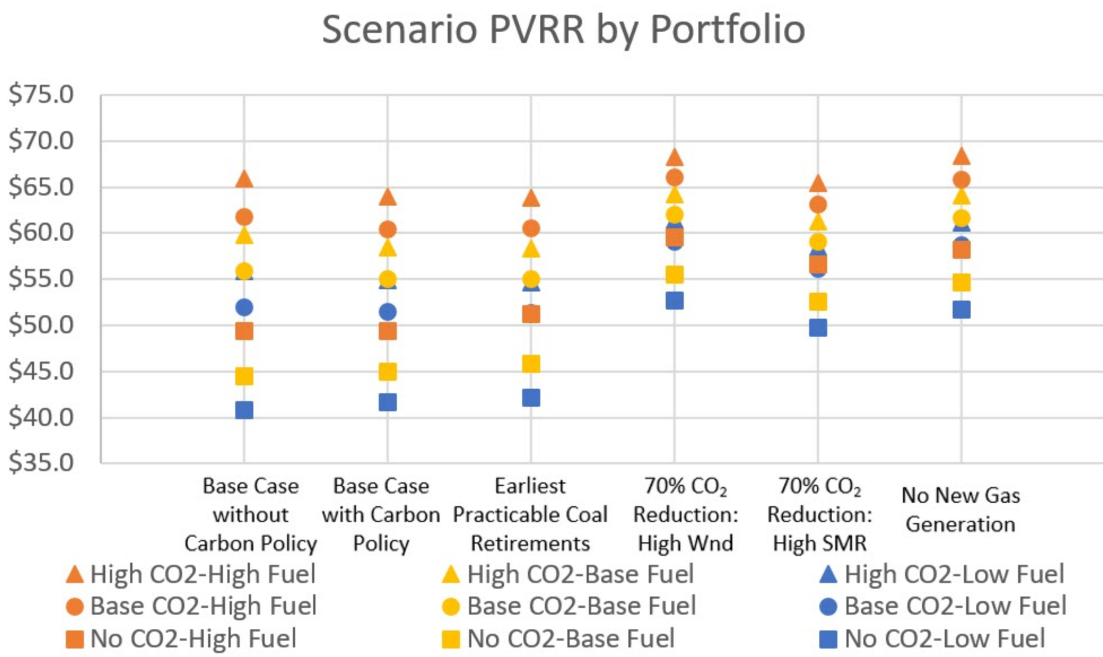
FIGURE A-11

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS



In contrast to the previous view, when the costs of carbon are included in the total cost of the plan, the range of PVRRs for each plan is increased. It can be seen that the Base Case without Carbon Policy is again the portfolio that is most sensitive to fuel and carbon policies. While the lowest cost for the Base Case with Carbon Policy and Earliest Practicable Retirements is higher than Base Case without Carbon Policy, the cost ceiling is lower, due to less natural gas on the system, with its associated carbon emissions and cost based on the price of natural gas. Again, the highest reduction plans, the 70% CO_2 Reduction plans and the No New Gas Generation Plan are less sensitive to the fuel and carbon variables, but are overall more expensive plans, though the gap is smaller when the cost of carbon is considered. The results of these PVRRs are dependent on the structural and policy changes that enable carbon reductions, which will be discussed later in this appendix.

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AVERAGE RESIDENTIAL MONTHLY BILL IMPACT

The total present value revenue requirement (PVRR) of a plan is a common and useful financial metric in Integrated Resource Planning to measure the cost of the plan over a long period of time. This metric will capture the costs and benefit of accelerating retirements, building new generation and associated transmission, and changing fuel prices and operation costs over time. While this is an important metric, the company is also concerned about the cost to customers on an immediate basis, as providing affordable energy is critical to the company's mission. The analysis of estimating the average residential monthly bill impact attempts to quantify how much a residential customer, using 1,000 kWh of energy a month, can expect to see their bill increase over 2020 costs of service due to the changes identified in this IRP. Below, Table A-17 that shows the resulting increase to a residential customers bill for each of the plans through 2030 and 2035 and the average annual percentage change from 2020 through 2030 and 2035, in the company's base gas price and base carbon price scenario, while excluding the explicit cost of the carbon tax to customer.

TABLE A-17

SCENARIO ANALYSIS AVERAGE MONTHLY RESIDENTIAL BILL IMPACT FOR A HOUSEHOLD USING 1000 KWH

	2030		2035	
	Average Residential Monthly Bill Impact	Average Annual Percentage Change in Residential Bills	Average Residential Monthly Bill Impact	Average Annual Percentage Change in Residential Bills
Base Case without Carbon Policy	$7	0.7%	$23	1.3%
Base Case with Carbon Policy	$8	0.8%	$25	1.5%
Earliest Practicable Coal Retirements	$13	1.3%	$25	1.4%
70% CO_2 Reductions: High Wind	$26	2.3%	$47	2.5%
70% CO_2 Reductions: High SMR	$24	2.2%	$45	2.5%
No New Gas Generation	$12	1.1%	$45	2.4%

Table A-17 shows that the plans with earlier transitions to lower carbon future portfolios and more expensive technologies will see greater cost increase to their bills earlier, while the plans that wait longer to transition, and allow for emerging technologies to decease in price, may lessen and defer some of those costs increases. With projected declining cost curves for emerging carbon-free resources the pace of adoption plays a critical role in the ultimate cost to consumers.

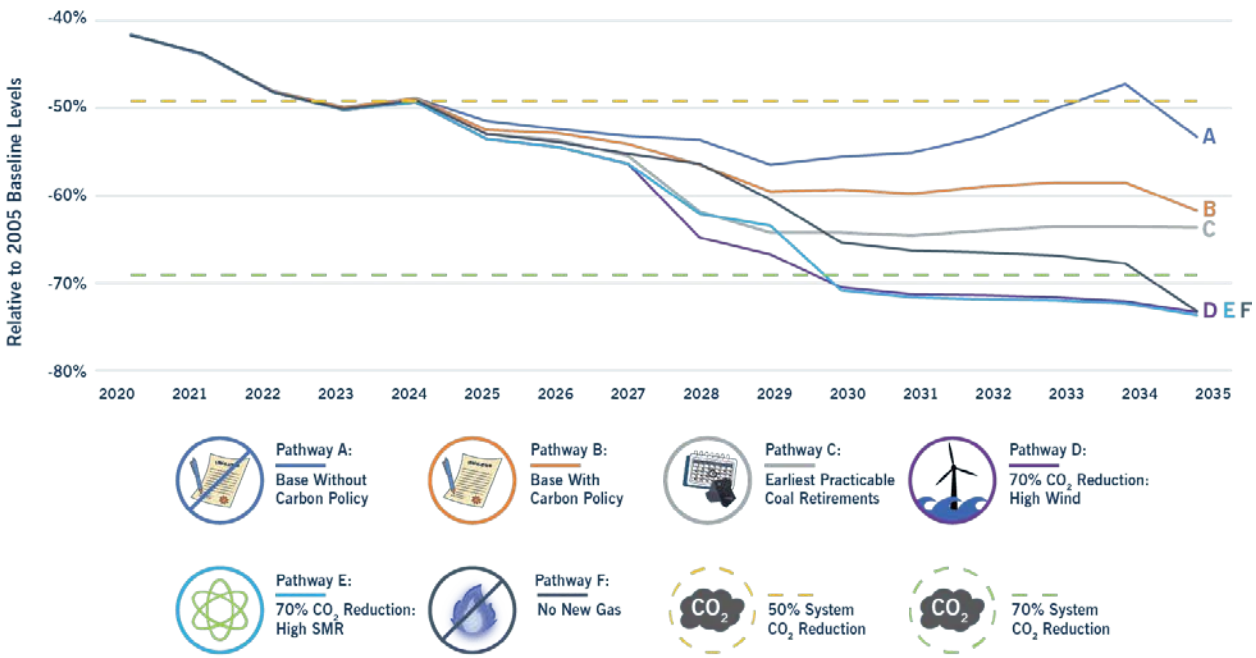
It should be noted that integrating large scale regional energy infrastructure projects, such as bringing offshore wind energy into the Carolinas, would likely require statewide policies. It is likely that the resources and the transmission infrastructure costs to move the energy from the coast to load centers could be spread across all customers in the state rather than those of a single utility. Notwithstanding this possibility, for the purposes of developing the No New Gas Portfolio, all energy, capacity, and associated costs for the results shown are for DEC only, with the recognition that future energy policy could more evenly spread costs across utilities.

PORTFOLIO CARBON REDUCTIONS ANALYSIS

While cost is undoubtably an important factor, one of the most crucial aspects analyzed in this IRP is the trade-off between costs and carbon reductions. The graph below charts the carbon reductions for the combined DEP/DEC system of each of the portfolios in the base fuel and base carbon scenario through the IRP planning window. The resources added throughout time, price on carbon emissions (or lack thereof), and relative price between carbon intense fuels influence these carbon emissions. Additional discussion is presented below.

FIGURE A-12

COMBINED DEP/DEC CARBON REDUCTION BY PORTFOLIO IN BASE FUEL AND BASE CARBON SCENARIO



Through 2024 there are no notable changes in carbon emission reductions between the portfolios. Base Planning without Carbon Policy (Pathway A) continues a trajectory of lowering carbon emissions through 2029, albeit at a slower pace than other pathways, as low cost, lower carbon intense natural gas and increasing penetration of solar offsets higher carbon intense coal generation. As gas price begins to rise in the transition from market fuel prices to fundamental fuel prices, less expensive coal generation becomes more prevalent when a carbon tax is not present. Upon retirement, and replacement of Marshall station in 2035, and replacement with was generation, pathway A sees a reduction in carbon emission again at the end of the planning horizon.

In 2025 the carbon tax comes into effect in pathways B through F, driving the emissions from carbon intense resources down. Increasing additions of solar generation along with the economic pressure of the price on carbon continues to drive carbon reductions in the Base Planning with Carbon Policy (Pathway B). Growing load and rising gas prices minimize the reductions realized by renewables additions in the 2030, resulting in flat CO_2 reduction until 2035, when Marshall is retired.

As coal and other traditional generation retirements take place throughout the mid-2020, the carbon reductions between the pathways begin to diverge, resulting in a range of carbon reduction of 56% to 71% from 2005 baseline. Pathways D and E continue to rise to 70% with the retirement of Belews Creek and Marshall Stations in these scenarios by 2030, where Pathways F flattens out from 2029 through 2035, when Marshall retires in this case. By 2035, Pathways D, E, and F converge again around 73%, when the resource types in these portfolios converge at the end of the IRP horizon with similar penetrations of non-carbon emitting resources.

TABLE A-18

SCENARIO REDUCTIONS IN 2030 FOR EACH PORTFOLIO

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	55.9%	58.7%	64.3%	70.5%	70.9%	64.9%
High CO_2-Base Fuel	56.6%	59.4%	64.3%	70.5%	70.8%	65.5%
High CO_2-Low Fuel	56.7%	59.5%	64.2%	70.5%	70.8%	65.6%
Base CO_2-High Fuel	55.7%	58.5%	64.3%	70.5%	70.8%	64.7%
Base CO_2-Base Fuel	56.4%	59.3%	64.2%	70.5%	70.8%	65.4%
Base CO_2-Low Fuel	56.7%	59.5%	64.2%	70.5%	70.8%	65.5%
No CO_2-High Fuel	53.4%	56.5%	64.2%	70.4%	70.8%	63.6%
No CO_2-Base Fuel	55.5%	58.4%	64.1%	70.4%	70.7%	64.6%
No CO_2-Low Fuel	56.0%	58.9%	63.9%	70.2%	70.4%	65.1%
Reduction Range	3.4%	3.0%	0.4%	0.3%	0.5%	2.0%

TABLE A-19

SCENARIO REDUCTIONS IN 2035 FOR EACH PORTFOLIO

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO^2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	56.3%	61.1%	63.6%	73.3%	73.7%	72.6%
High CO_2-Base Fuel	57.2%	61.9%	63.6%	73.3%	73.6%	73.3%
High CO_2-Low Fuel	57.3%	62.0%	63.6%	73.3%	73.6%	73.5%
Base CO_2-High Fuel	54.3%	59.3%	63.6%	73.3%	73.6%	72.1%
Base CO_2-Base Fuel	57.0%	61.7%	63.6%	73.3%	73.6%	73.2%
Base CO_2Low Fuel	57.2%	61.9%	63.6%	73.3%	73.6%	73.5%
No CO_2-High Fuel	49.4%	54.9%	63.6%	73.3%	73.6%	68.1%
No CO_2-Base Fuel	53.2%	58.3%	63.6%	73.3%	73.6%	71.1%
No CO_2-Low Fuel	55.5%	60.4%	63.5%	73.2%	73.5%	72.6%
Reduction Range	7.9%	7.1%	0.2%	0.1%	0.1%	5.4%

Through 2030, the plans with the most sensitivity in carbon emissions are the Base Cases, again due to their continued operations of Coal through the most economic retirement dates, and the additions of natural gas generation throughout the planning horizon. The CO_2 reduction range for the remaining four portfolios is relatively tight, within a 0.5% or less variance for the plans the utilize the earliest practicable retirement dates, and 2% for No New Gas Generation, which does not deploy new natural gas, but relies on the most economic retirement dates of the coal units for deployment of other existing and emerging technologies to replace the retiring capacity.

These observations though 2030 are amplified by 2035. The cases with the most economic coal retirement dates see ranges of carbon reductions from 7.9% in the Base Case without Carbon Policy to 5.4% in the No New Gas Generation plan. Conversely, the plans with the higher costs also deliver consistency in carbon reductions, with emission varying very little with changes to carbon and fuel pricing.

IDENTIFYING OPPORTUNITIES AND RISK MITIGATION

While each of these plans comes with inherent risks, such as exposure to fuel and carbon pricing or early adoption of emerging technologies with cost and operational uncertainties, the utility will have to continue to have constructive conversations with stakeholders, regulators, and customers to identify and mitigate risks that would prevent the company from providing clean, affordable, and reliable energy. Below discusses some of these risks and mitigating measure:

- **Earliest Practicable Coal Retirements –** While the PVRR and Average Residential Monthly Bill Impact results for Earliest Practicable Coal Retirements are relatively comparable to the Base Case with Carbon Policy, this portfolio does present additional potential tradeoffs and dependency on a number of factors. The regulatory approval and feasibility of procuring the replacement generation are foremost on this list. Additionally, some of the earliest practicable coal retirement are predicated on replacement onsite, leveraging existing infrastructure. This assumption avoids transmission upgrades at some of the retiring coal sites to reduce replacement timelines, and results in lower costs of the plan. The most economic retirement dates of the coal units do not assumed replacement at site, and do not benefit from this cost saving. This provides optionality in the replacement process for the cheapest alternatives to be selected but does incur more cost to the plan for the associated transmission upgrades. Project cost risks associated with these accelerated retirements may put stresses on supply chain driving price variations. Furthermore, deploying economically maturing technologies, like batteries, at large scale may increase cost and operational risk, while opting for earlier retirement of coal units by relying on natural gas may impact of deploying lower carbon and ZEFLR technologies in the future or the associated customer impact to do so.

- **Solar Interconnection –** While solar and other intermittent technologies may help lower exposure to variability in the price of fuels and can help reduce carbon emissions, the interconnection and operation of these resources will have to continue to be studied and advanced to allow for affordable and reliable operation of the system.

- **Onshore Wind Integration –** Several studies throughout the industry identify the value of combining variable energy resources like solar and wind with different but potentially complimentary production profiles. Integration of these resources can help continue to lower

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carbon emissions and spur economic development in the region but overcoming the historic challenges to siting onshore wind in the Carolinas is an issue that requires further study.

- **Offshore Wind Integration –** A largely untapped resource sits just a few miles off the coast of the Carolinas. While there are several hurdles to incorporating this new generation source in the Carolinas systems, such as construction of these wind resources, transmitting that energy to land and then delivering it to the Company's load centers, there is a great opportunity to further reduce carbon emissions and add bulk amounts of zero fuel cost generation to the fleet.

- **ZELFR Development –** While emerging technologies, such as SMRs, were deployed in this IRP, the general development of zero-emitting, load following resources across a range of options will be important to de-risking the transition to a net-zero carbon future.

- **System Operability –** The system operators will have to continue to learn and adapt to new, intermittent and variable energy resources on the system to balance load and generation, utilizing and advancing the flexibility of the existing fleet, while leveraging resources like energy storage and demand side management to continue to provide safe and reliable energy. These transformations envisioned will also rely on significant advancements in the sophistication of the grid control systems needed to manage system operations with these more diverse and distributed new energy resources.

OTHER FINDINGS AND INSIGHTS

- **Gas as a transition fuel -** The No New Gas Generation portfolio in this IRP demonstrates that natural gas remains a cost-effective way to accelerate the remaining coal retirements over the term of this IRP. Many independent studies and articles have supported the continued role of natural gas to balance the intermittency of renewables and continue to decarbonize the system. As shown in the emissions trajectories graph, the No New Gas portfolio emits more CO_2, over the fifteen-year period through 2035 and is significantly more costly than the 70% Carbon Reduction by 2030 portfolios (D and E) that include natural gas as a replacement resource. Eliminating natural gas generation as an option is likely to have the unintended effect of delaying coal retirements and increasing CO_2 in the interim, as more coal generation is required to serve load without new efficient natural gas resources as a transition technology.

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- **Gas transportation services -** On July 5th, 2020 Dominion Energy and Duke Energy announced the cancellation of Atlantic Coast Pipeline (ACP) citing anticipated delays and increasing cost uncertainty due to on-going permitting and legal challenges. DEP and DEC still need additional firm interstate transportation service to support existing and future gas generation in the Carolinas despite the cancellation of the project. The 2020 IRP assumes incremental firm transportation service volumes as contemplated in the ACP project are needed from alternate pipeline providers to cost effectively support both existing natural gas generation fleet and future combined cycle natural gas generation growth. Additionally, incremental firm interstate transportation service is assumed to be procured for any new combined cycle natural gas resource selected in the generation portfolios in this IRP along with firm transportation service cost estimates. The estimated firm transportation service costs were considered in the resource selection process and are included in the financial results presented. Consistent with past IRPs, the planning process does not assume incremental interstate capacity is procured for additional simple cycle CTs given their low capacity factors. Rather, CTs are planned as dual fuel units that are ultimately connected to Transco Zone 5 and will rely on delivered Zone 5 gas supply or if needed ultra-low sulfur fuel oil during winter periods where natural gas has limited availability, the pipeline has additional constraints, or gas is higher priced than the cost to operate on fuel oil. Additional discussion on ACP and Fuel Supply can be found in Appendix F.

- **Discussion on Levelized Cost of Energy (LCOE) -** A common source of confusion over the economics of replacement generation for coal retirements are "Levelized Cost of Energy" reports that attempt to compare all-in costs divided by total energy production on a $/MWh basis. While this can be a useful high-level economic screening tool, it does not speak to the capacity value of a resource, nor does it recognize time value differences in energy production, which can vary dramatically as is the case with high levels of renewable resources. Simple LCOE analysis ignores the reality that it can take several times the amount of installed capacity of certain intermittent resources to produce the same reliability of dispatchable resources, even if those resources are paired with energy storage. This multiplier effect can create additional hurdles related to the permitting and interconnection of a significantly larger amount of resources (on a nameplate MW basis), which naturally has cost implications. To illustrate the multiplier effect, the Company has developed a Portfolio Screening Tool which will be released to the public shortly after the IRP filing.

- **Emerging technologies decommissioning costs -** Industry research is beginning to address decommissioning challenges and costs and potential materials recycling opportunities for these new and emerging technologies. While there are allowances for some costs at end of life, more information will be needed to forecast these costs and the resource selections are being made.

- **A balanced approach to aggressive carbon reduction goals –** The company has stated that a balanced portfolio of resources with varying attributes to produce carbon-free energy, respond to variations in load and generation, shift energy, and reduce overall energy and demand is an important aspect for the Company to consider in resource planning. A combination and blend of these resources in the portfolio may help reduce reliance on the development or price declines of a single resource type and provide the system with the balance of attribute to reliably and more affordably meet the customers' energy needs.

VALUE OF JOINT PLANNING

To demonstrate the value of sharing capacity with DEP, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Case with Carbon Policy plans for DEC and DEP would change if a 17% minimum winter planning reserve margin was applied at the combined system level, rather than the individual company level.

An evaluation was performed comparing the Base Case with Carbon Policy plans for DEC and DEP to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEC and DEP to meet the 17% minimum winter planning reserve margin. Table A-20 shows the base expansion plans (Base Case with Carbon Policy for both DEC and DEP) through 2035, if separately planned, compared to the Joint Planning Case. The sum of the two combined resource requirements is then compared to the amount of resources needed if DEC and DEP could jointly plan for capacity. Planned projects and the economic selection of renewables and batteries were not reoptimized for this sensitivity. Delaying and accelerating of gas units was used to preserve the joint system's 17% reserve margin. Years where the Joint Planning Case differ from the individual Utility cases are highlighted.

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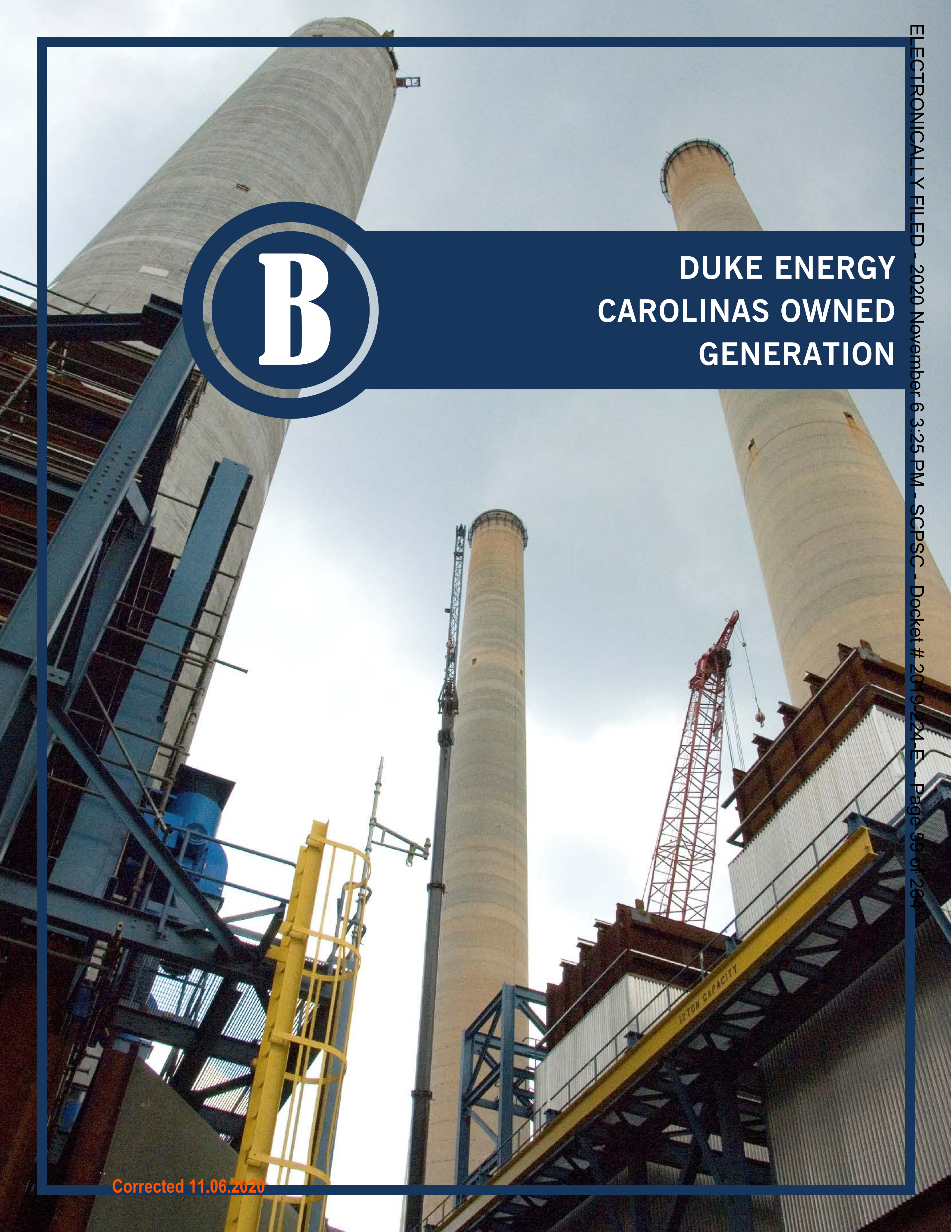
TABLE A-20

COMPARISON OF BASE CASE WITH CARBON POLICY OF INDIVIDUAL UTILITY PLANNING TO JOINT PLANNING SENSITIVITY

	INDIVIDUAL UTILITY PLANNING					
	DEC		DEP		COMBINED SYSTEM	
	CC	CT	CC	CT	CC	CT
2021	0	0	0	0	0	0
2022	0	0	0	0	0	0
2023	0	0	0	0	0	0
2024	0	0	0	0	0	0
2025	0	0	0	0	0	0
2026	0	0	0	457	0	457
2027	0	0	0	914	0	914
2028	0	0	1,224	914	1,224	914
2029	0	0	2,448	1,828	2,448	1,828
2030	0	457	2,448	1,828	2,448	2,285
2031	0	914	2,448	1,828	2,448	2,742
2032	0	914	2,448	1,828	2,448	2,742
2033	0	914	2,448	1,828	2,448	2,742
2034	0	914	2,448	1,828	2,448	2,742
2035	1,224	1,828	2,448	1,828	3,672	3,656

	JOINT PLANNING	
	COMBINED SYSTEM	
	CC	CT
2021	0	0
2022	0	0
2023	0	0
2024	0	0
2025	0	0
2026	0	457
2027	0	457
2028	1,224	914
2029	2,448	1,828
2030	2,448	1,828
2031	2,448	2,285
2032	2,448	2,285
2033	2,448	2,742
2034	2,448	2,742
2035	3,672	3,199

A comparison of the DEC and DEP Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer a CT resource starting in 2027. Consequently, the Joint Planning Case also results in a lower overall reserve margin. This is confirmed by a review of the reserve margins for the Combined Base Case as compared to the Joint Planning Case, which averaged 18.2% and 18.3%, respectively, from the first need in DEP in 2026 over the remaining IRP planning horizon. The ability to share resources and achieve incrementally lower reserve margins from year to year in the Joint Planning Case illustrates the efficiency and economic potential for DEC and DEP when planning for capacity jointly. Finally, as discussed in the Company's updated Resource Adequacy Study the benefits of a joint system can have beneficial results and could potentially lead to even a slightly lower reserve margin than the 17% examined in the Joint Planning Case.



B

DUKE ENERGY CAROLINAS OWNED GENERATION

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APPENDIX B: DUKE ENERGY CAROLINAS OWNED GENERATION

Duke Energy Carolinas' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements.

The tables below list the Duke Energy Carolinas' plants in service in North Carolina and South Carolina with plant statistics, and the system's total generating capability.

DUKE ENERGY CAROLINAS

EXISTING GENERATING UNITS AND RATINGS [A, B, C, D, E, F, G]
ALL GENERATING UNIT RATINGS ARE AS OF JANUARY 1, 2020

COAL									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Allen	1	167	162	Belmont, N.C.	Coal	Peaking	62	4	N/A
Allen	2	167	162	Belmont, N.C.	Coal	Peaking	62	2	N/A
Allen	3	270	258	Belmont, N.C.	Coal	Peaking	60	2	N/A
Allen	4	267	257	Belmont, N.C.	Coal	Intermediate	59	2	N/A
Allen	5	259	259	Belmont, N.C.	Coal	Peaking	58	4	N/A
Belews Creek	1	1110	1110	Belews Creek, N.C.	Coal	Base	45	19	N/A
Belews Creek	2	1110	1110	Belews Creek, N.C.	Coal	Base	44	19	N/A
Cliffside	5	546	544	Cliffside, N.C.	Coal	Peaking	47	6	N/A
Cliffside	6	849	844	Cliffside, N.C.	Coal	Intermediate	7	29	N/A
Marshall	1	380	370	Terrell, N.C.	Coal	Intermediate	54	15	N/A
Marshall	2	380	370	Terrell, N.C.	Coal	Intermediate	53	15	N/A
Marshall	3	658	658	Terrell, N.C.	Coal	Base	50	15	N/A
Marshall	4	660	660	Terrell, N.C.	Coal	Base	49	15	N/A
Total Coal		6,823	6,764						

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COMBUSTION TURBINES									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Lee	7C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking	12	28	N/A
Lee	8C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking	12	28	N/A
Lincoln	1	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	2	99	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	3	99	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	4	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	5	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	6	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	7	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	8	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	9	97	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	10	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	11	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	12	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	13	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	23	16	N/A
Lincoln	14	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	23	16	N/A
Lincoln	15	98	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	23	16	N/A
Lincoln	16	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	23	16	N/A

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COMBUSTION TURBINES (CONT.)									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Mill Creek	1	94	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	17	24	N/A
Mill Creek	2	94	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	17	24	N/A
Mill Creek	3	95	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	17	24	N/A
Mill Creek	4	94	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	17	24	N/A
Mill Creek	5	94	69	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	16	24	N/A
Mill Creek	6	92	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	16	24	N/A
Mill Creek	7	95	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	16	24	N/A
Mill Creek	8	93	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	16	24	N/A
Rockingham	1	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Rockingham	2	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Rockingham	3	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Rockingham	4	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Rockingham	5	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Total NC		2,460	2,018						
Total SC		847	647						
Total CT		3,307	2,665						

Corrected 11.06.2020

NATURAL GAS FIRED BOILER									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Lee	3	173	170	Pelzer, S.C.	Natural Gas	Peaking	61	11	N/A
Total Nat. Gas		173	170						

Corrected 11.06.2020

COMBINED CYCLE									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Buck	CT11	206	178	Salisbury, N.C.	Natural Gas	Base	8	32	N/A
Buck	CT12	206	178	Salisbury, N.C.	Natural Gas	Base	8	32	N/A
Buck	ST10	304	312	Salisbury, N.C.	Natural Gas	Base	8	32	N/A
Buck CTCC		716	668						
Dan River	CT8	199	171	Eden, N.C.	Natural Gas	Base	7	33	N/A
Dan River	CT9	199	171	Eden, N.C.	Natural Gas	Base	7	33	N/A
Dan River	ST7	320	320	Eden, N.C.	Natural Gas	Base	7	33	N/A
Dan River CTCC		718	662						
WS Lee	CT11	240	237	Pelzer, S.C.	Natural Gas	Base	1	N/A	N/A
WS Lee	CT12	239	236	Pelzer, S.C.	Natural Gas	Base	1	N/A	N/A
WS Lee	ST10	313	313	Pelzer, S.C.	Natural Gas	Base	1	N/A	N/A
WS Lee CTCC		792	786						
Total CTCC		2,226	2,116						

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COMBINED HEAT & POWER									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Clemson CHP	GT01	15.7	12.8	Pickens, S.C.	Natural Gas	Base	1 month	N/A	N/A
Total CHP		15.7	12.8						

Corrected 11.06.2020

PUMPED STORAGE									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Jocassee	1	195	195	Salem, S.C.	Pumped Storage	Peaking	46	27	2046
Jocassee	2	195	195	Salem, S.C.	Pumped Storage	Peaking	46	27	2046
Jocassee	3	195	195	Salem, S.C.	Pumped Storage	Peaking	44	27	2046
Jocassee	4	195	195	Salem, S.C.	Pumped Storage	Peaking	44	27	2046
Bad Creek	1	340	340	Salem, S.C.	Pumped Storage	Peaking	28	39	2027
Bad Creek	2	340	340	Salem, S.C.	Pumped Storage	Peaking	28	39	2027
Bad Creek	3	340	340	Salem, S.C.	Pumped Storage	Peaking	28	39	2027
Bad Creek	4	340	340	Salem, S.C.	Pumped Storage	Peaking	28	39	2027
Total Pump. Storage		2,140	2,140						

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HYDRO									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
99 Islands	1	4.2	4.2	Blacksburg, S.C.	Hydro	Peaking	109	N/A	2036
99 Islands	2	3.4	3.4	Blacksburg, S.C.	Hydro	Peaking	109	N/A	2036
99 Islands	3	4.2	4.2	Blacksburg, S.C.	Hydro	Peaking	109	N/A	2036
99 Islands	4	3.4	3.4	Blacksburg, S.C.	Hydro	Peaking	109	N/A	2036
Bear Creek	1	9.5	9.5	Tuckasegee, N.C.	Hydro	Peaking	65	N/A	2041
Bridgewater	1	15	15	Morganton, N.C.	Hydro	Peaking	100	N/A	2055
Bridgewater	2	15	15	Morganton, N.C.	Hydro	Peaking	100	N/A	2055
Bridgewater	3	1.5	1.5	Morganton, N.C.	Hydro	Peaking	100	N/A	2055
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro	Peaking	67	N/A	2041
Cedar Cliff	2	0.4	0.4	Tuckasegee, N.C.	Hydro	Peaking	67	N/A	2041
Cedar Creek	1	15	15	Great Falls, S.C.	Hydro	Peaking	93	N/A	2055
Cedar Creek	2	15	15	Great Falls, S.C.	Hydro	Peaking	93	N/A	2055
Cedar Creek	3	15	15	Great Falls, S.C.	Hydro	Peaking	93	N/A	2055
Cowans Ford	1	81	81	Stanley, N.C.	Hydro	Peaking	56	N/A	2055
Cowans Ford	2	81	81	Stanley, N.C.	Hydro	Peaking	56	N/A	2055
Cowans Ford	3	81	81	Stanley, N.C.	Hydro	Peaking	56	N/A	2055
Cowans Ford	4	81	81	Stanley, N.C.	Hydro	Peaking	52	N/A	2055

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HYDRO (CONT.)									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Dearborn	1	14	14	Great Falls, S.C.	Hydro	Peaking	96	N/A	2055
Dearborn	2	14	14	Great Falls, S.C.	Hydro	Peaking	96	N/A	2055
Dearborn	3	14	14	Great Falls, S.C.	Hydro	Peaking	96	N/A	2055
Fishing Creek	1	11	11	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Fishing Creek	2	10	10	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Fishing Creek	3	10	10	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Fishing Creek	4	11	11	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Fishing Creek	5	8	8	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Great Falls	1	3	3	Great Falls, S.C.	Hydro	Peaking	112	N/A	2055
Great Falls	2	3	3	Great Falls, S.C.	Hydro	Peaking	112	N/A	2055
Great Falls	5	3	3	Great Falls, S.C.	Hydro	Peaking	112	N/A	2055
Great Falls	6	3	3	Great Falls, S.C.	Hydro	Peaking	112	N/A	2055
Keowee	1	76	76	Seneca, S.C.	Hydro	Peaking	48	N/A	2046
Keowee	2	76	76	Seneca, S.C.	Hydro	Peaking	48	N/A	2046
Lookout Shoals	1	9.0	9.0	Statesville, N.C.	Hydro	Peaking	104	N/A	2055
Lookout Shoals	2	9.0	9.0	Statesville, N.C.	Hydro	Peaking	104	N/A	2055
Lookout Shoals	3	9.0	9.0	Statesville, N.C.	Hydro	Peaking	104	N/A	2055
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro	Peaking	96	N/A	2055
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro	Peaking	96	N/A	2055
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro	Peaking	96	N/A	2055
Mountain Island	4	17	17	Mount Holly, N.C.	Hydro	Peaking	96	N/A	2055
Nantahala	1	50	50	Topton, N.C.	Hydro	Peaking	77	N/A	2042

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HYDRO (CONT.)	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Oxford	1	20	20	Conover, N.C.	Hydro	Peaking	91	N/A	2055
Oxford	2	20	20	Conover, N.C.	Hydro	Peaking	91	N/A	2055
Queens Creek	1	1.4	1.4	Topton, N.C.	Hydro	Peaking	70	N/A	2032
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro	Peaking	94	N/A	2055
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro	Peaking	94	N/A	2055
Rhodhiss	3	12.4	12.4	Rhodhiss, N.C.	Hydro	Peaking	94	N/A	2055
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro	Peaking	64	N/A	2041
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro	Peaking	78	N/A	2041
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro	Peaking	69	N/A	2041
Wateree	1	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wateree	2	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wateree	3	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wateree	4	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wateree	5	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wylie	1	18	18	Fort Mill, S.C.	Hydro	Peaking	94	N/A	2055
Wylie	2	18	18	Fort Mill, S.C.	Hydro	Peaking	94	N/A	2055
Wylie	3	18	18	Fort Mill, S.C.	Hydro	Peaking	94	N/A	2055
Wylie	4	6	6	Fort Mill, S.C.	Hydro	Peaking	94	N/A	2055
Total NC		617.6	617.6						
Total SC		461.2	461.2						
Total Hydro		1,078.8	1,078.8						

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SOLAR									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
NC Solar		76	76	N.C.	Solar	Intermediate	Various	N/A	N/A
Total Solar		76	76						

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NUCLEAR									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
McGuire	1	1199.0	1158.0	Huntersville, N.C.	Nuclear	Base	38	44	2041
McGuire	2	1187.2	1157.6	Huntersville, N.C.	Nuclear	Base	35	44	2043
Catawba	1	1198.7	1160.1	York, S.C.	Nuclear	Base	34	44	2043
Catawba	2	1179.8	1150.1	York, S.C.	Nuclear	Base	34	44	2043
Oconee	1	865	847	Seneca, S.C.	Nuclear	Base	46	35	2033
Oconee	2	872	848	Seneca, S.C.	Nuclear	Base	45	35	2033
Oconee	3	881	859	Seneca, S.C.	Nuclear	Base	45	35	2034
Total NC		2,386.2	2,315.6						
Total SC		4,996.5	4,864.2						
Total Nuclear		7,382.7	7,179.8						

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TOTAL GENERATION CAPABILITY		
	WINTER CAPACITY (MW)	SUMMER CAPACITY (MW)
TOTAL DEC SYSTEM - N.C.	13,796.8	13,121.2
TOTAL DEC SYSTEM – S.C.	9,425.4	9,081.2
TOTAL DEC SYSTEM	23,222.2	22,202.4

NOTE a: Unit information is provided by State, but resources are dispatched on a system-wide basis.

NOTE b: Cliffside also called the Rogers Energy Center.

NOTE c: Catawba Units 1 and 2 capacity reflects 100% of the station's capability.

NOTE d: WS Lee Combined Cycle (CC) Units CT11, CT12 and ST10 reflects 100% of the CC's capability and does not factor in the 100 MW of capacity owned by NCEMC. The DEC – NCEMC Joint-Owner contract includes an energy buyback provision for DEC of the capacity owned by NCEMC in the WS Lee CC facility.

NOTE e: Solar capacity ratings reflect nameplate capacity.

NOTE f: Lee Unit 3 summer capacity rating reflects nameplace value.

NOTE g: Resource type based on NERC capacity factor classifications which may alternate over the forecast period.

NOTE h: The Catawba units' multiple owners and their effective ownership percentages are:

CATAWBA OWNER	PERCENT OF OWNERSHIP
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
PMPA	12.5%

PLANNED ADDITIONS / UPRATES			
UNIT	DATE	WINTER MW	SUMMER MW
Bad Creek 1	Sept 2021	65.0	65.0
Bad Creek 2	Sept 2020	65.0	65.0
Bad Creek 3	Sept 2022	65.0	65.0
Bad Creek 4	Sept 2023	65.0	65.0
Oconee 1	Jan 2023	15.0	15.0
Oconee 2	Jan 2022	15.0	15.0
Oconee 3	May 2022	15.0	15.0
Catawba 1	May 2020	6.0	6.0
Catawba 2	Apr 2021	6	6
Clemson CHP	Nov 2020	15.0	15.0

NOTE: This capacity not reflected in unit ratings in above tables.

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RETIREMENTS				
UNIT AND PLANT NAME	LOCATION	CAPACITY (MW) SUMMER	FUEL TYPE	RETIREMENT DATE
Buck 3[a]	Salisbury, N.C.	75	Coal	05/15/11
Buck 4[a]	Salisbury, N.C.	38	Coal	05/15/11
Cliffside 1[a]	Cliffside, N.C.	38	Coal	10/1/11
Cliffside 2[a]	Cliffside, N.C.	38	Coal	10/1/11
Cliffside 3[a]	Cliffside, N.C.	61	Coal	10/1/11
Cliffside 4[a]	Cliffside, N.C.	61	Coal	10/1/11
Dan River 1[a]	Eden, N.C.	67	Coal	04/1/12
Dan River 2[a]	Eden, N.C.	67	Coal	04/1/12
Dan River 3[a]	Eden, N.C.	142	Coal	04/1/12
Buzzard Roost 6C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 7C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 8C	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 9C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 10C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 11C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 12C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 13C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 14C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 15C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Riverbend 8C[b]	Mt. Holly, N.C.	0	Combustion Turbine	10/1/12
Riverbend 9C[b]	Mt. Holly, N.C.	22	Combustion Turbine	10/1/12
Riverbend 10C[b]	Mt. Holly, N.C.	22	Combustion Turbine	10/1/12
Riverbend 11C[b]	Mt. Holly, N.C.	20	Combustion Turbine	10/1/12

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RETIREMENTS (CONT.)				
Buck 7C [b]	Spencer, N.C.	25	Combustion Turbine	10/1/12
Buck 8C [b]	Spencer, N.C.	25	Combustion Turbine	10/1/12
Buck 9C [b]	Spencer, N.C.	12	Combustion Turbine	10/1/12
Dan River 4C [b]	Eden, N.C.	0	Combustion Turbine	10/1/12
Dan River 5C [b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Dan River 6C [b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Riverbend 4 [a]	Mt. Holly, N.C.	94	Coal	04/1/13
Riverbend 5 [a]	Mt. Holly, N.C.	94	Coal	04/1/13
Riverbend 6 [c]	Mt. Holly, N.C.	133	Coal	04/1/13
Riverbend 7 [c]	Mt. Holly, N.C.	133	Coal	04/1/13
Buck 5 [c]	Spencer, N.C.	128	Coal	04/1/13
Buck 6 [c]	Spencer, N.C.	128	Coal	04/1/13
Lee 1 [d]	Pelzer, S.C.	100	Coal	11/6/14
Lee 2 [d]	Pelzer, S.C.	100	Coal	11/6/14
Lee 3 [e]	Pelzer, S.C.	170	Coal	05/12/15*
Great Falls 3	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 4	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 7	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 8	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 1	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 2	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 3	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 4	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 5	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 6	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 7	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 8	Great Falls, S.C.	0	Hydro	05/31/18
Ninety-Nine Islands 5	Blacksburg, S.C.	0	Hydro	12/31/18
Ninety-Nine Islands 6	Blacksburg, S.C.	0	Hydro	12/31/18
Bryson City 1 [f]	Whittier, N.C.	.5	Hydro	08/16/2019
Bryson City 2 [f]	Whittier, N.C.	.4	Hydro	08/16/2019
Franklin 1 [f]	Franklin, N.C.	.5	Hydro	08/16/2019
Franklin 2 [f]	Franklin, N.C.	.5	Hydro	08/16/2019
Gaston Shoals 3 [f]	Blacksburg, S.C.	0	Hydro	08/16/2019
Gaston Shoals 4 [f]	Blacksburg, S.C.	0	Hydro	08/16/2019

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RETIREMENTS (CONT.)				
Gaston Shoals 5 [f]	Blacksburg, S.C.	2	Hydro	08/16/2019
Gaston Shoals 6 [f]	Blacksburg, S.C.	2.5	Hydro	08/16/2019
Mission 1 [f]	Murphy, N.C.	.6	Hydro	08/16/2019
Mission 2 [f]	Murphy, N.C.	.6	Hydro	08/16/2019
Mission 3 [f]	Murphy, N.C.	.6	Hydro	08/16/2019
Tuxedo 1 [f]	Flat Rock, N.C.	3.2	Hydro	08/16/2019
Tuxedo 2 [f]	Flat Rock, N.C.	3.2	Hydro	08/16/2019
	Total	2,051.6 MW		

NOTE a: Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

NOTE b: The old fleet combustion turbines retirement dates were accelerated in 2009 based on derates, availability of replacement parts and the general condition of the remaining units.

NOTE c: The decision was made to retire Buck 5 and 6 and Riverbend 6 and 7 early on April 1, 2013. The original expected retirement date was April 15, 2015.

NOTE d: Lee Steam Units 1 and 2 were retired November 6, 2014.

NOTE e: The conversion of the Lee 3 coal unit to a natural gas unit was effective March 12, 2015.

NOTE f: Sold to Northbrook Energy 8/16/2019.

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PLANNING ASSUMPTIONS – UNIT RETIREMENTS [a,b,c]					
Unit & Plant Name	Location	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Expected Retirement
Allen 1	Belmont, NC	167	162	Coal	12/2023
Allen 2	Belmont, NC	167	162	Coal	12/2021
Allen 3	Belmont, NC	270	261	Coal	12/2021
Allen 4	Belmont, NC	282	276	Coal	12/2021
Allen 5	Belmont, NC	275	266	Coal	12/2023
Belews Creek 1	Belews Creek, NC	1,110	1,110	Coal	12/2038
Belews Creek 2	Belews Creek, NC	1,110	1,110	Coal	12/2038
Cliffside 5	Cliffside, NC	546	544	Coal	12/2025
Cliffside 6	Cliffside, NC	844	844	Coal	12/2048
Marshall 1	Terrell, NC	380	370	Coal	12/2034
Marshall 2	Terrell, NC	380	370	Coal	12/2034
Marshall 3	Terrell, NC	658	658	Coal	12/2034
Marshall 4	Terrell, NC	660	660	Coal	12/2034
Lee 3	Pelzer, SC	173	160	NG	12/2030
Total		7,022	6,953		

NOTE a: Retirement assumptions are for planning purposes only; retirement dates based on the LCR in the 2020 Integrated Resource Plan.

NOTE b: Coal unit retirement dates based on most economic retirement dates as determined in the Coal Retirement Study (see Chapter 11).

NOTE c: For planning purposes, the 2020 IRP Base Case assumes subsequent license renewal for existing nuclear facilities beginning at end of current operating licenses. Total planning retirements exclude nuclear capacities.

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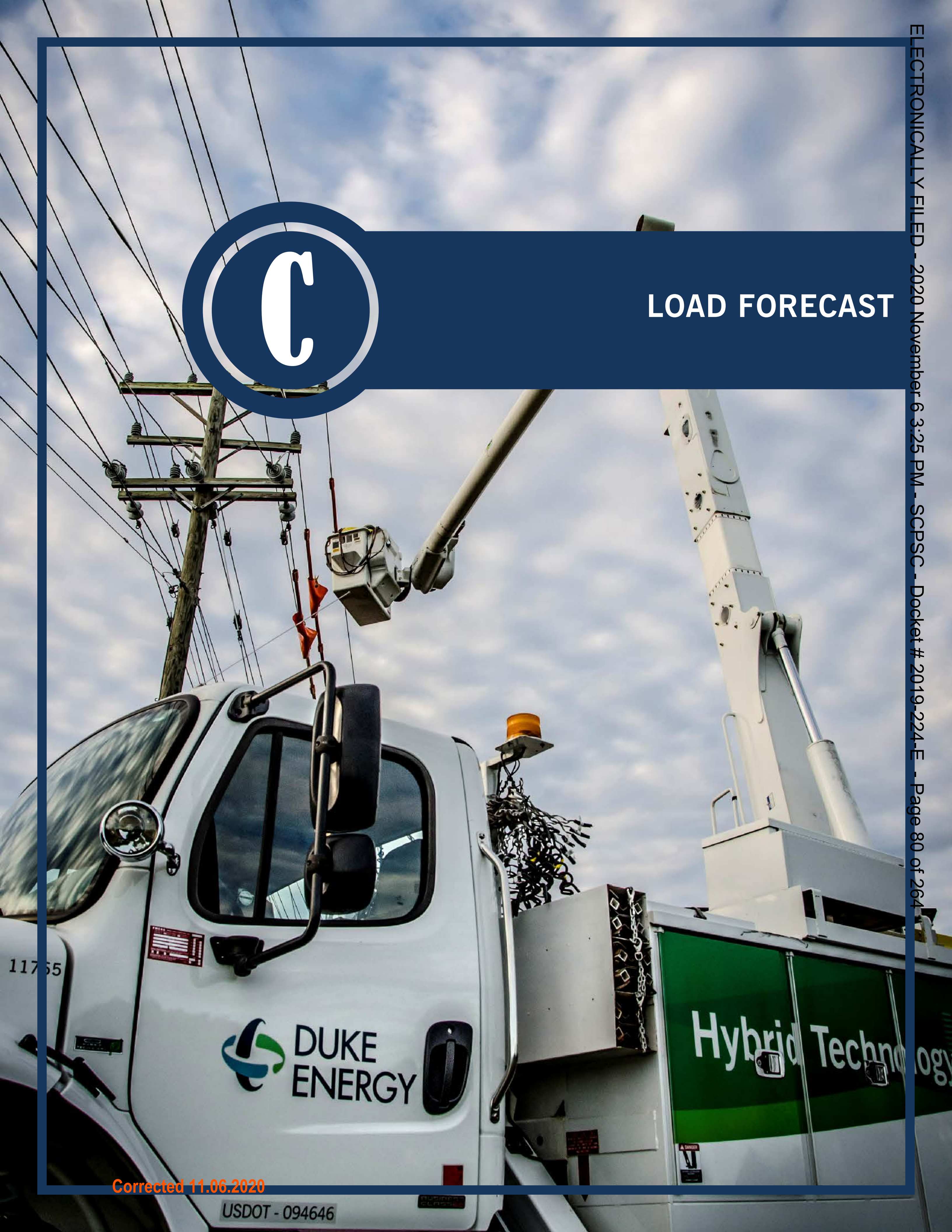
OPERATING LICENSE RENEWAL

Operating License Renewal - Nuclear				
Plant and Unit Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Catawba Unit 1	York, SC	12/6/2024	12/5/2003	12/5/2043
Catawba Unit 2	York, SC	2/24/2026	12/5/2003	12/5/2043
McGuire Unit 1	Huntersville, NC	6/12/2021	12/5/2003	6/12/2041
McGuire Unit 2	Huntersville, NC	3/3/2023	12/5/2003	3/3/2043
Oconee Unit 1	Seneca, SC	2/6/2013	5/23/2000	2/6/2033
Oconee Unit 2	Seneca, SC	10/6/2013	5/23/2000	10/6/2033
Oconee Unit 3	Seneca, SC	7/19/2014	5/23/2000	7/19/2034



C

LOAD FORECAST

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APPENDIX C: ELECTRIC LOAD FORECAST

METHODOLOGY

The Duke Energy Carolinas' Spring 2020 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2021 – 2035 and represents the needs of the following customer classes:

DEC LOAD FORECAST CUSTOMER CLASSES

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the residential customer model.

The economic projections used in the Spring 2020 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North and South Carolina. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models.

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The Spring 2020 forecast was developed using Moody's economic inputs as of January 2020. Therefore; the disruptions experienced due to COVID-19 are not incorporated in this forecast. We are continuing to monitor the impacts seen to both energies and peaks, and currently think that the longer-term impacts will be minimal. We will however continue to evaluate the impacts, and update future forecasts for expected impacts.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial. The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The average annual growth rate for the residential class in the Spring 2020 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2021 – 2035 is 1.5%.

The Commercial forecast also uses an SAE model to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the commercial class are offices, education and retail. Commercial energy sales are expected to grow 0.5% per year over the forecast horizon.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to decline 0.2% per year over the forecast horizon.

Weather impacts are incorporated into the models by using Heating Degree Days with a base temperature of 59 and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 30-year average, which is updated every year.

The appliance saturation and efficiency trends are developed by Itron using data from the Energy Information Administration (EIA). Itron is a recognized firm providing forecasting services to the electric utility industry. These appliance trends are used in the residential and commercial sales models.

Peak demands were projected using the SAE approach. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

FORECAST ENHANCEMENTS

In 2013, the Company began using the SAE model projections to forecast sales and peaks. The end use models provide a better platform to recognize trends in equipment / appliance saturation and changes to efficiencies, and how those trends interact with heating, cooling, and "other" or non-weather-related sales. These appliance trends are used in the residential and commercial sales models. In conjunction with peer utilities and ITRON, the company continually looks for refinements to its modeling procedures to make better use of the forecasting tools and develop more reliable forecasts.

Each time the forecast is updated, the most currently available historical and projected data is used. The current 2020 forecast utilizes:

- Moody's Analytics January 2020 base and consensus economic projections.
- End use equipment and appliance indexes reflect the 2019 update of ITRON's end-use data, which is consistent with the Energy Information Administration's 2019 Annual Energy Outlook
- A calculation of normal weather using the period 1990-2019

The Company also researches weather sensitivity of summer and winter peaks, peak history, hourly shaping of sales, and load research data in a continuous effort to improve forecast accuracy. As a result of continuous improvement efforts, refinements to peak history were identified during the Spring 2020 update, which lowered peak history. Peak history is a key driver in the peak forecast, thus the revisions also contributed to the decrease in the peak forecast. Historical peaks and forecasted peaks can be viewed later in this appendix.

ASSUMPTIONS

Below are the projected average annual growth rates of several key drivers from DEC's Spring 2020 Forecast.

TABLE C-1

KEY DRIVERS

	2021-2035
Real Income	2.9%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.5%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of UEE, as well as projected effects of electric vehicles and behind the meter solar technology.

UTILITY ENERGY EFFICIENCY

Utility Energy Efficiency (UEE) Programs continue to have a large impact in the acceleration of the adoption of energy efficiency. When including the energy and peak impacts of UEE, careful attention must be paid to avoid the double counting of UEE efficiencies with the naturally occurring efficiencies included in the SAE modeling approach. To ensure there is not a double counting of these efficiencies, the forecast "rolls off" the UEE savings at the conclusion of its measure life. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 7 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 7 are subtracted ("rolled off") from the total cumulative UEE. With the SAE model's framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

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The table below illustrates this process on sales:

TABLE C-2

UEE PROGRAM LIFE PROCESS (GWH)

YEAR	FORECAST BEFORE UEE	HISTORICAL UEE ROLL OFF	FORECAST WITH HISTORICAL ROLL OFF	FORECASTED UEE INCREMENTAL ROLL ON	FORECASTED UEE INCREMENTAL ROLL OFF	UEE TO SUBTRACT FROM FORECAST	FORECAST AFTER UEE
2021	91,601	8	91,609	(1,269)	657	(612)	90,997
2022	92,121	42	92,162	(1,974)	985	(988)	91,174
2023	92,757	106	92,863	(2,667)	1,314	(1,353)	91,541
2024	93,404	217	93,622	(3,344)	1,644	(1,700)	91,981
2025	93,647	375	94,022	(4,003)	1,975	(2,029)	92,292
2026	94,141	562	94,702	(4,631)	2,306	(2,325)	92,677
2027	94,657	754	95,411	(5,222)	2,640	(2,582)	93,129
2028	95,236	931	96,167	(5,777)	2,985	(2,792)	93,677
2029	95,802	1,070	96,872	(6,294)	3,360	(2,933)	94,242
2030	96,371	1,162	97,533	(6,774)	3,789	(2,985)	94,852
2031	97,018	1,218	98,236	(7,229)	4,241	(2,987)	95,554
2032	97,626	1,242	98,869	(7,675)	4,715	(2,959)	96,216
2033	98,119	1,250	99,370	(8,118)	5,240	(2,878)	96,799
2034	98,625	1,250	99,875	(8,558)	5,793	(2,766)	97,419
2035	99,158	1,250	100,409	(8,997)	6,423	(2,574)	98,145

ROOFTOP SOLAR AND ELECTRIC VEHICLES

Rooftop solar photovoltaic (PV) and electric vehicles (EVs) are considered load modifiers: behind-the-meter solar PV generation reduces the effective load that Duke Energy serves, while plug-in EV charging increases load on the system. Rooftop solar generation and EV load are forecasted independently and then combined with base load and UEE impacts to produce the final electric load forecast. Impacts from existing rooftop solar and EVs are embedded in the historical data that the base load forecast is derived from. Therefore, forecasts for rooftop solar and EVs include impacts from only incremental or “net new” resources projected to be added within the planning horizon.

With the variable characteristics of solar generation and mobility of EVs, utilities will need to employ advanced system controls and/or time-of-use incentives for optimal grid management in order to provide safe, reliable and cost-effective service to customers. Given that DEC does not currently have dispatch control of rooftop solar or EVs, DEC's load forecast accounts for the variability of uncontrolled generation and charging. If advanced controls are employed in the future, the forecasted shape would better align with system capabilities and needs.

The markets for rooftop solar and EVs are growing rapidly, so it will become increasingly important to understand and accurately forecast their impacts on electric load. Additional discussion related to regulatory policy and technology can be found in Appendix E.

ROOFTOP SOLAR

Rooftop solar refers to behind-the-meter solar PV generation for residential, commercial and industrial customers. Energy produced by the solar array is consumed by the customer, offsetting their demand on the electric grid. Any excess energy is exported to the grid and credited to the customer at full retail rates under current net energy metering (NEM) policies in North and South Carolina. Both NC and SC have requirements to revisit their NEM tariffs, so while DEC assumes there will be changes to the current program within the planning horizon, it is not yet clear what those changes may be. For this IRP, DEC assumes that NEM tariffs will evolve to more closely align with the cost to serve rooftop solar customers, such that bill savings would gradually decrease over time. This reduction is offset by declining technology costs and increased customer preferences for self-generation, leading to a forecasted net increase in rooftop solar adoption.

Rooftop solar exports are beneficial as a source of carbon-free energy, but present challenges for grid operators due to intermittency associated with solar generation, reduced visibility of the resource and lack of control of energy supply.

Under full retail net metering policy, rooftop solar systems have typically been sized to offset 100% of a customer's annual average demand, within the constraints of state policy. Residential customers are limited to 20 kW-AC, and non-residential customers are limited to the lesser of 1 MW-AC or 100% demand per NC HB 589 and SC Act 62.

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TABLE C-3
AVERAGE ROOFTOP SOLAR CAPACITY (kW-AC)

CUSTOMER CLASS	DEC-NC	DEC-SC
Residential	6.2	8.2
Non-residential	77	118

The rooftop solar generation forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial and industrial customer classes.

Each capacity forecast is the product of a customer adoption forecast and an average capacity value. Adoption forecasts are based on linear regression modeling in Itron MetrixND using customer payback period as the primary independent variable. Payback periods are a function of installed cost, regulatory incentives and electric bill savings. Historical and projected technology costs are provided by Navigant. Projected incentives and bill savings are based on current regulatory policies and input from internal subject matter experts. Average capacity values are based on trends in historical adoption.

Hourly production profiles have “12x24” resolution meaning there is one 24-hour profile for each month. Profiles are derived from actual production data, where available, and solar PV modeling. Modeling is performed in PVsyst using over 20 years of historical irradiance data from Solar Anywhere and Solcast. Models are created for 13 irradiance locations across DEC’s service area and 21 tilt/azimuth configurations. Results are combined on a weighted average basis to produce final profiles.

Table C-4 shows the projected incremental additions of rooftop solar customers, along with the impacts on capacity and energy, in NC and SC, at the beginning and end of the planning horizon.

TABLE C-4
ROOFTOP SOLAR, NET NEW FROM 2020

YEAR	STATE	NUMBER OF CUSTOMERS	PERCENT OF CUSTOMERS	CAPACITY (MW)	ENERGY (MWH/YEAR)
2021	NC	10,600	0.5%	105	111,000
	SC	3,200	0.5%	29	26,000
2035	NC	79,100	3.1%	745	984,000
	SC	67,000	9.1%	582	710,000

ELECTRIC VEHICLES

EV charging represents a significant opportunity for load growth in the planning horizon. Wood Mackenzie projects EV charging infrastructure to nearly quintuple by 2025[1], and BloombergNEF projects EVs to increase U.S. load by 2% in 2030 and 10% in 2040[2].

Duke Energy's EV load forecast is derived from a series of EV forecasts and load profiles.

The Electric Power Research Institute (EPRI) provides EV forecasts specific to DEC's service area for three adoption cases (low, medium and high) and five vehicle types. In recent years Duke Energy has used EPRI's medium adoption case with minor adjustments as needed for known or expected changes in the market. Vehicle types include plug-in EVs with 10-, 20- and 40-mile range and fully electric vehicles with 100 and 250-mile range.

Unique hourly load profiles (kWh per vehicle per day) are developed internally for each vehicle type, for weekdays and weekends, and for residential and public charging.

[1] Wood Mackenzie: US DER Outlook (June 2020).
[2] BloombergNEF: 2020 Electric Vehicle Outlook: U.S. Update (June 2020).

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Table C-5 shows the projected incremental additions of EVs in operation, along with the impacts on energy, at the beginning and end of the planning horizon.

TABLE C-5

ELECTRIC VEHICLES, NET NEW FROM 2020, INCLUDES NC AND SC

YEAR	EVS IN OPERATION	PERCENT OF VEHICLE FLEET	LOAD (MWH/YEAR)
2021	17,800	0.2%	21,000
2035	417,000	7.3%	1,474,000

NET IMPACT OF ROOFTOP SOLAR AND ELECTRIC VEHICLES

Figures C-1, C-2 and C-3 illustrate the impacts on annual energy, winter peak demand and summer peak demand from rooftop solar and EVs by customer class across the planning horizon.

FIGURE C-1

PERCENT IMPACT OF PV AND EV ON ANNUAL LOAD, NET NEW FROM 2020

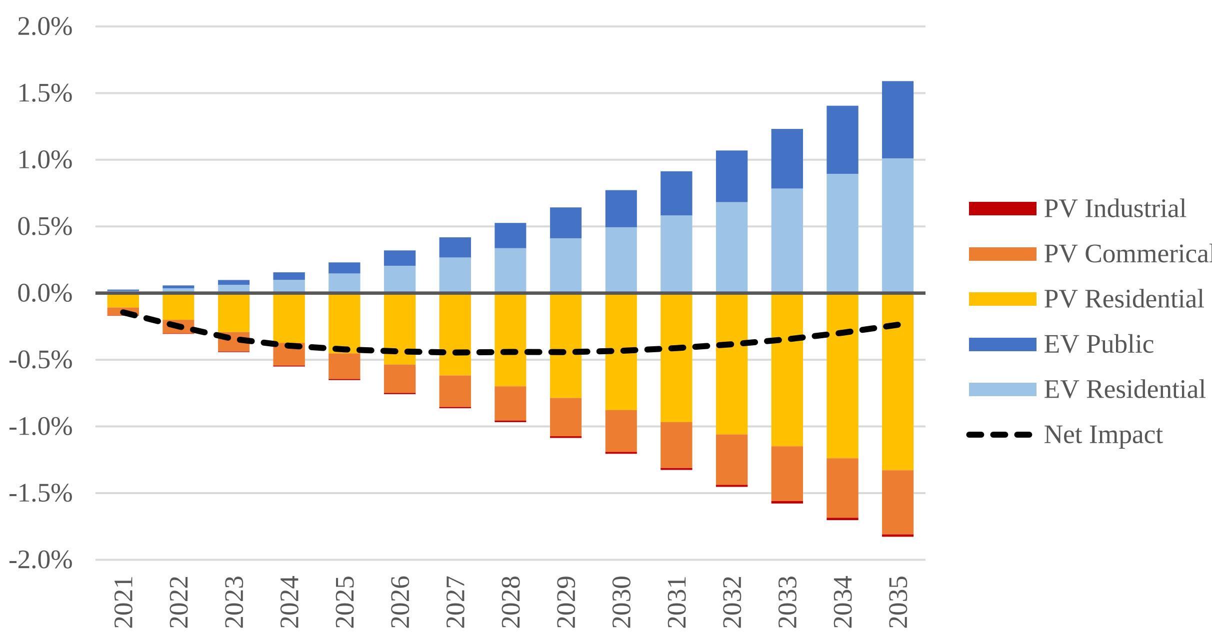

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FIGURE C-2

PERCENT IMPACT OF PV AND EV ON WINTER PEAK LOAD, NET NEW FROM 2020

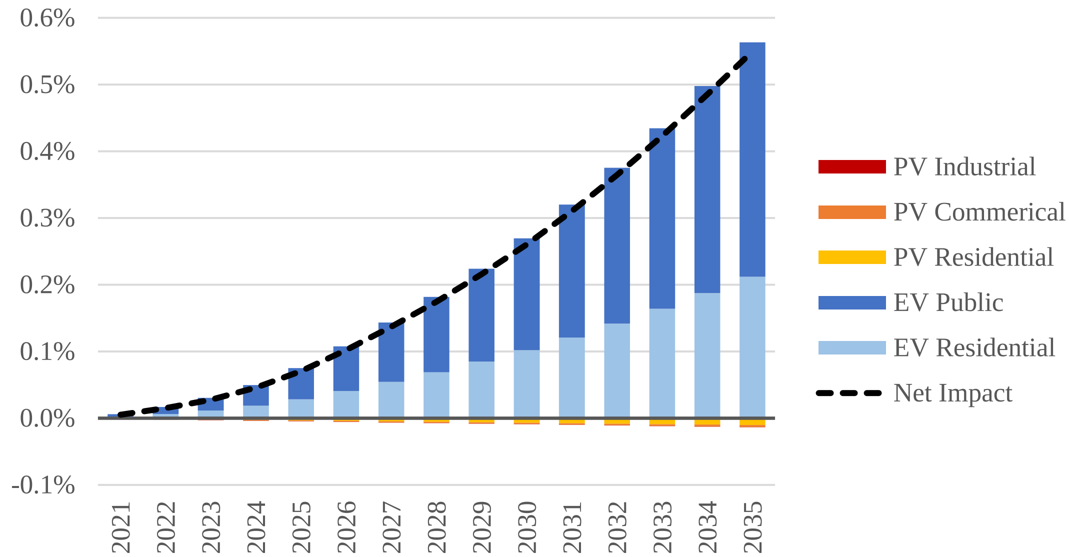
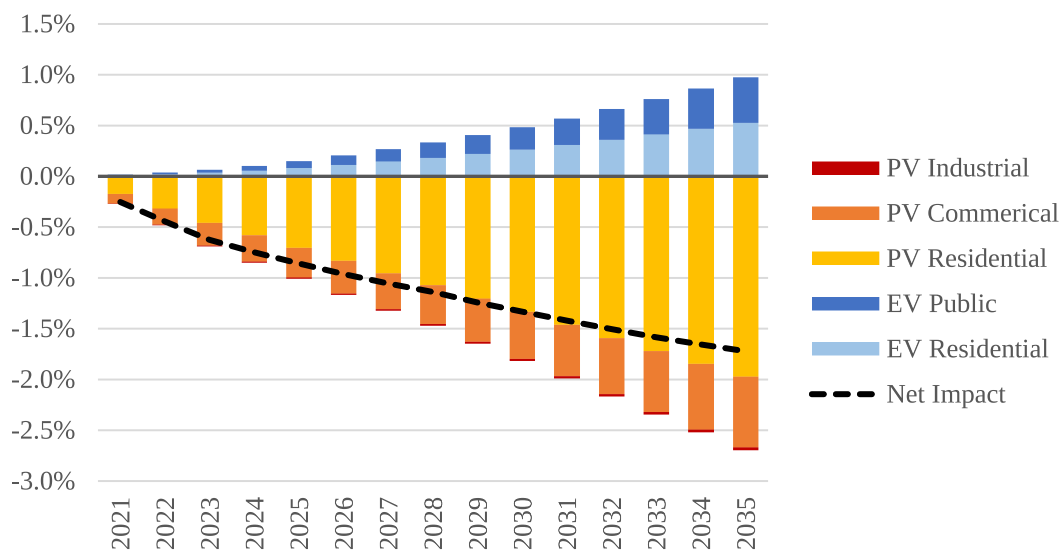


FIGURE C-3

PERCENT IMPACT OF PV AND EV ON SUMMER PEAK LOAD, NET NEW FROM 2020



CUSTOMER GROWTH

Tables C-6 and C-7 show the history and projections for DEC customers.

TABLE C-6
RETAIL CUSTOMERS (ANNUAL AVERAGE IN THOUSANDS)

YEAR	RESIDENTIAL CUSTOMERS	COMMERCIAL CUSTOMERS	INDUSTRIAL CUSTOMERS	OTHER CUSTOMERS	RETAIL CUSTOMERS
2010	2,034	333	7	14	2,389
2011	2,041	335	7	14	2,397
2012	2,053	337	7	14	2,411
2013	2,068	339	7	14	2,428
2014	2,089	342	7	15	2,452
2015	2,117	345	6	15	2,484
2016	2,148	349	6	15	2,519
2017	2,182	354	6	15	2,557
2018	2,215	358	6	17	2,596
2019	2,261	362	6	22	2,651
Avg. Annual Growth Rate	1.2%	0.9%	-2.0%	5.0%	1.2%

TABLE C-7

RETAIL CUSTOMERS (THOUSANDS, ANNUAL AVERAGE)

YEAR	RESIDENTIAL CUSTOMERS	COMMERCIAL CUSTOMERS	INDUSTRIAL CUSTOMERS	OTHER CUSTOMERS	RETAIL CUSTOMERS
2021	2,324	367	6	23	2,721
2022	2,362	369	6	23	2,761
2023	2,405	371	6	24	2,805
2024	2,447	373	6	24	2,850
2025	2,489	374	6	24	2,894
2026	2,529	376	6	25	2,936
2027	2,568	378	6	25	2,976
2028	2,606	379	6	25	3,016
2029	2,643	381	6	25	3,055
2030	2,680	382	6	26	3,094
2031	2,718	383	5	26	3,133
2032	2,755	385	5	26	3,171
2033	2,791	386	5	27	3,209
2034	2,826	388	5	27	3,246
2035	2,860	389	5	27	3,281
Avg. Annual Growth Rate	1.5%	0.4%	-1.1%	1.1%	1.3%

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ELECTRICITY SALES

Table C-8 shows the actual historical gigawatt hour (GWh) sales. As a note, the values in Table C-8 are not weather adjusted Sales.

TABLE C-8
ELECTRICITY SALES (GWH)

YEAR	RESIDENTIAL GWH	COMMERCIAL GWH	INDUSTRIAL GWH	MILITARY & OTHER GWH	RETAIL GWH	WHOLESALE GWH	TOTAL SYSTEM GWH
2010	30,049	27,968	20,618	287	78,922	5,166	84,088
2011	28,323	27,593	20,783	287	76,986	4,866	81,852
2012	26,279	27,476	20,978	290	75,023	5,176	80,199
2013	26,895	27,765	21,070	293	76,023	5,824	81,847
2014	27,976	28,421	21,577	303	78,277	6,559	84,836
2015	27,916	28,700	22,136	305	79,057	6,916	85,973
2016	27,939	28,906	21,942	304	79,091	7,614	86,705
2017	26,593	28,388	21,776	301	77,059	7,558	84,617
2018	29,717	29,656	21,720	306	81,399	8,889	90,288
2019	28,861	29,628	21,299	320	80,109	8,317	88,426
Avg. Annual Growth Rate	-0.4%	0.6%	0.4%	1.2%	0.2%	5.4%	0.6%

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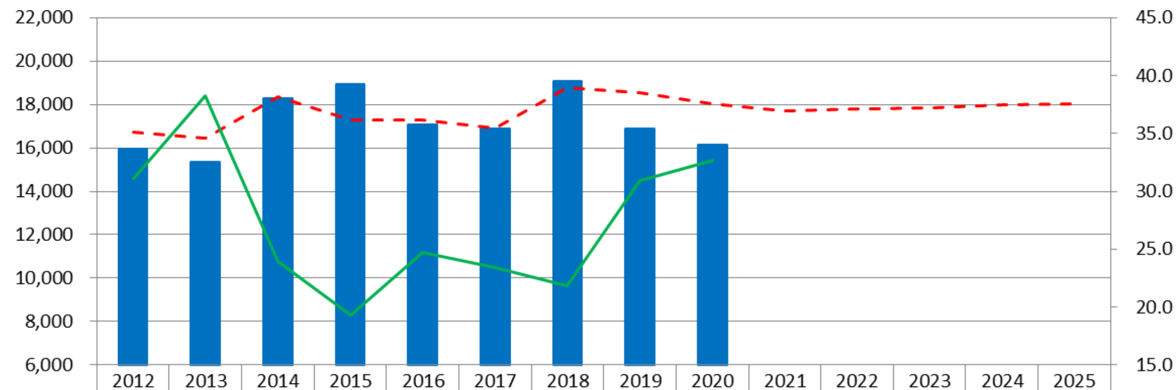
SYSTEM PEAKS

Figures C-4 and C-5 show the historical actual and weather normalized peaks for the system:

FIGURE C-4
DEC ACTUAL AND WEATHER NORMAL WINTER PEAKS



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actual	15,962	15,363	18,275	18,931	17,073	16,883	19,077	16,880	16,132					
WN Peak/Forecast	16,733	16,464	18,362	17,294	17,305	16,908	18,783	18,548	18,038	17,725	17,804	17,859	17,962	18,031
Temp	31.1	38.3	23.9	19.4	24.7	23.4	21.9	30.9	32.7					

Note: WN Peak/Forecast values in years 2021-2025 are forecasted peak values from the 2020 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak.

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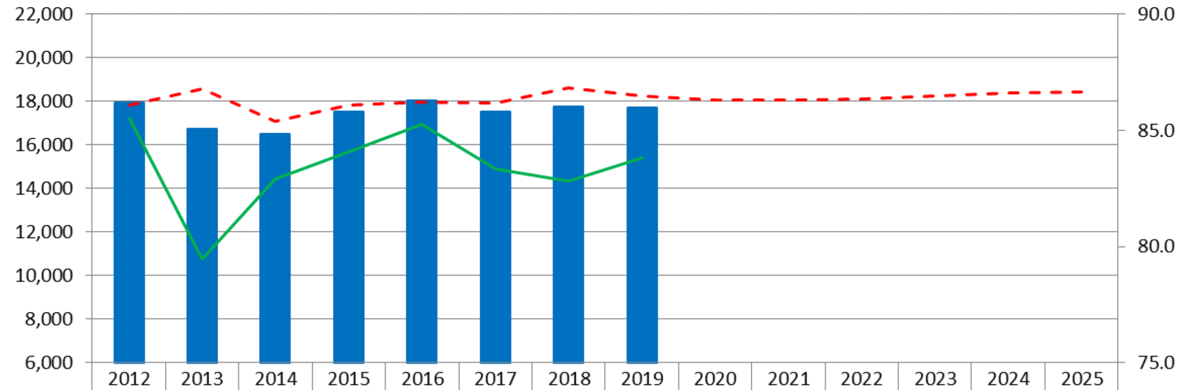
FIGURE C-5

DEC ACTUAL AND WEATHER NORMAL SUMMER PEAKS



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actual	17,933	16,757	16,501	17,529	18,037	17,539	17,779	17,736						
WN Peak/Forecast	17,822	18,593	17,093	17,832	17,992	17,917	18,613	18,233	18,044	18,086	18,110	18,268	18,388	18,458
Temp	85.5	79.5	82.9	84.1	85.3	83.3	82.8	83.8						

Note: WN Peak/Forecast values in years 2020-2025 are forecasted peak values from the 2020 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak.

FORECAST RESULTS

A tabulation of the utility's sales and peak forecasts are shown as charts below:

- Table C-9: Forecasted energy sales by class (Including the impacts of UEE, rooftop solar, and electric vehicles)
- Table C-10: Forecast energy sales – gross load to net load (walkthrough of impacts from UEE, rooftop solar, electric vehicles and voltage control program)
- Table C-11: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs
- Table C-12: Summary of the load forecast with UEE programs and excluding any impacts from demand reduction programs

These projections include Wholesale, and all the loads and energy in the tables and charts below are at generation, except for the class sales forecast, which is at meter.

Load duration curves, with and without UEE programs are shown as Figures C-6 and C-7.

The values in these tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2021 to 2035.

TABLE C-9
FORECASTED ENERGY SALES BY CLASS

YEAR	RESIDENTIAL GWH	COMMERCIAL GWH	INDUSTRIAL GWH	OTHER GWH	RETAIL GWH
2021	28,612	29,257	20,909	320	79,098
2022	28,944	29,356	20,815	319	79,434
2023	29,271	29,461	20,677	317	79,725
2024	29,649	29,572	20,540	316	80,075
2025	29,917	29,668	20,423	314	80,321
2026	30,192	29,803	20,322	311	80,628
2027	30,467	29,958	20,267	309	81,001
2028	30,757	30,143	20,247	306	81,453
2029	31,043	30,332	20,252	303	81,929
2030	31,346	30,528	20,270	300	82,445
2031	31,670	30,722	20,283	297	82,971
2032	32,023	30,906	20,270	294	83,492
2033	32,372	31,085	20,253	290	84,000
2034	32,723	31,278	20,244	287	84,532
2035	33,074	31,516	20,289	284	85,163
Avg. Annual Growth Rate	1.0%	0.5%	-0.2%	-0.8%	0.5%

NOTE: Values are at meter.

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TABLE C-10

FORECASTED ENERGY SALES – GROSS LOAD TO NET LOAD

YEAR	GROSS RETAIL SALES	ENERGY EFFICIENCY	ROOFTOP SOLAR	ELECTRIC VEHICLES	VOLTAGE CONTROL (IVVC)	NET RETAIL SALES
2021	79,826	(612)	(138)	21		79,098
2022	80,625	(988)	(249)	46		79,434
2023	81,389	(1,353)	(362)	81	(30)	79,725
2024	82,160	(1,700)	(453)	129	(60)	80,075
2025	82,998	(2,029)	(542)	191	(298)	80,321
2026	83,619	(2,325)	(634)	268	(299)	80,628
2027	84,260	(2,582)	(730)	353	(301)	81,001
2028	84,924	(2,792)	(827)	450	(302)	81,453
2029	85,548	(2,933)	(938)	555	(303)	81,929
2030	86,111	(2,985)	(1,051)	674	(304)	82,445
2031	86,628	(2,987)	(1,170)	806	(305)	82,971
2032	87,100	(2,959)	(1,296)	954	(307)	83,492
2033	87,498	(2,878)	(1,423)	1,111	(308)	84,000
2034	87,878	(2,766)	(1,556)	1,285	(309)	84,532
2035	88,268	(2,574)	(1,694)	1,474	(311)	85,163

NOTE: Values are at meter.

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TABLE C-11

SUMMARY OF THE LOAD FORECAST WITHOUT UEE PROGRAMS AND EXCLUDING ANY IMPACTS FROM DEMAND REDUCTION PROGRAMS

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	18,198	17,795	91,609
2022	18,284	17,933	92,162
2023	18,498	18,042	92,863
2024	18,670	18,195	93,622
2025	18,787	18,334	94,022
2026	18,976	18,493	94,702
2027	19,181	18,607	95,411
2028	19,358	18,790	96,167
2029	19,501	18,933	96,872
2030	19,738	19,074	97,533
2031	19,907	19,226	98,236
2032	20,124	19,393	98,869
2033	20,237	19,502	99,370
2034	20,420	19,605	99,875
2035	20,533	19,752	100,409
Avg. Annual Growth Rate	0.9%	0.7%	0.7%

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FIGURE C-6

LOAD DURATION CURVE WITHOUT ENERGY EFFICIENCY PROGRAMS AND BEFORE DEMAND REDUCTION PROGRAMS

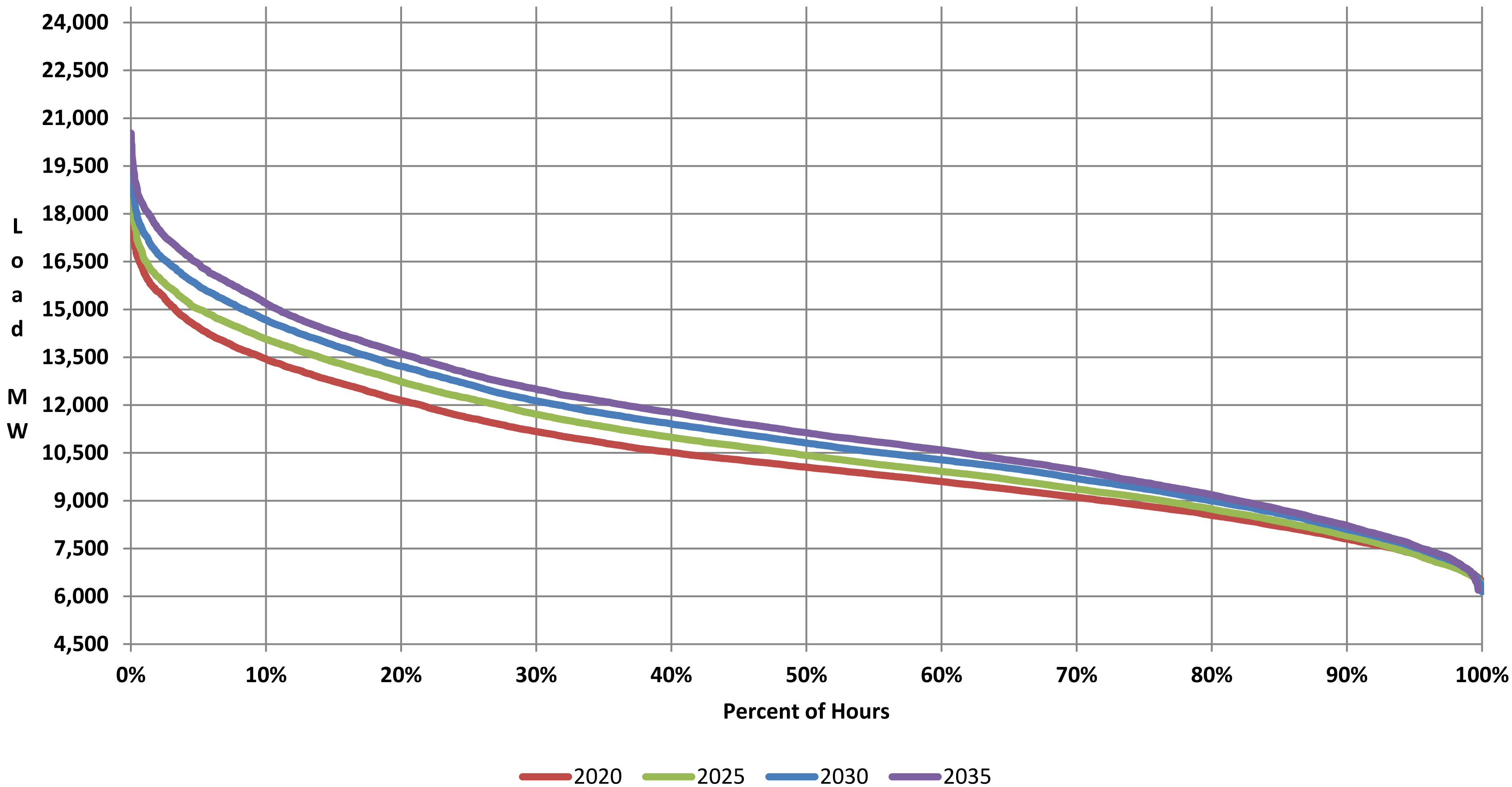

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TABLE C-12

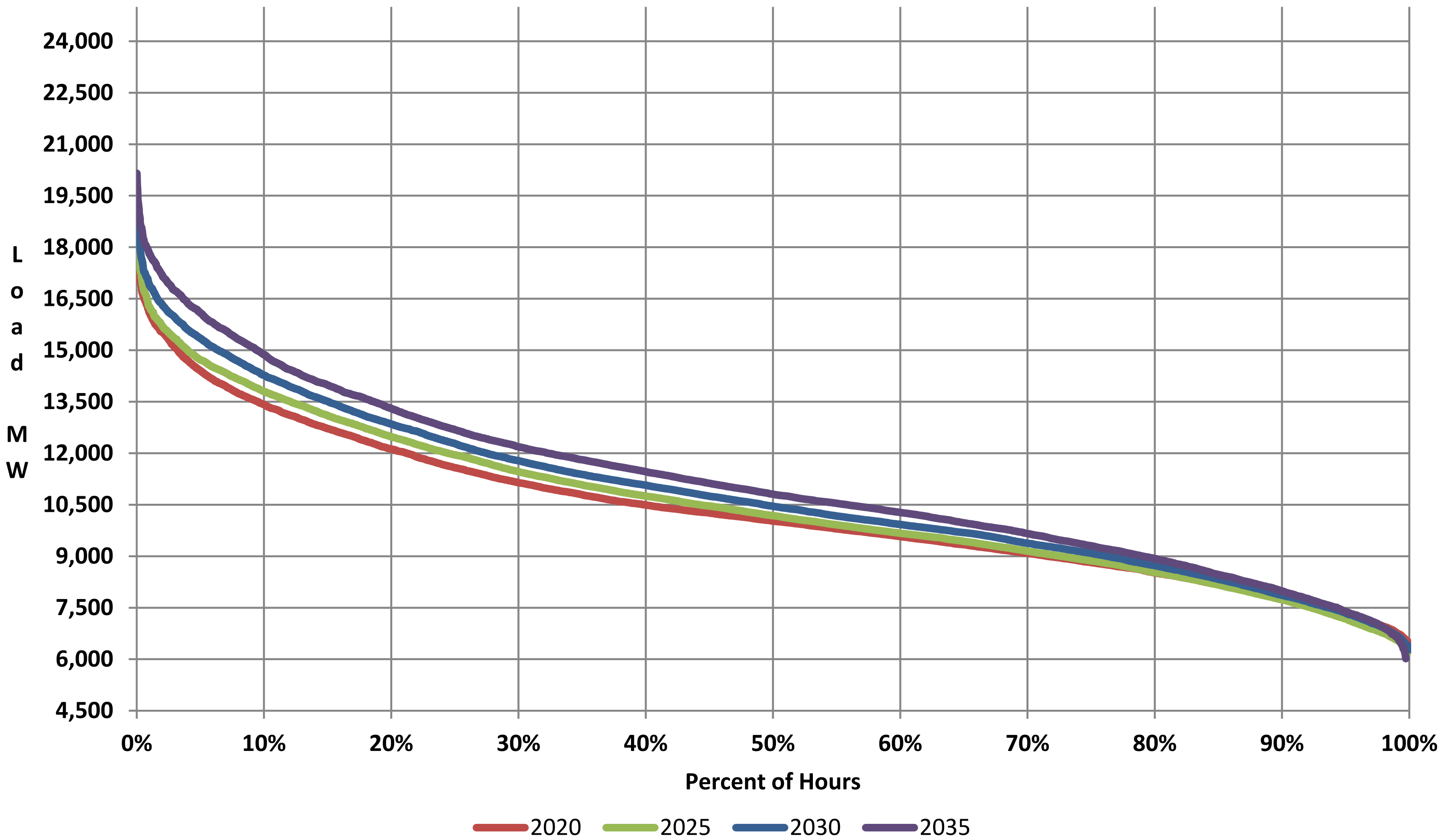
SUMMARY OF THE LOAD FORECAST WITH UEE PROGRAMS AND EXCLUDING ANY IMPACTS FROM DEMAND REDUCTION PROGRAMS

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	18,086	17,725	90,997
2022	18,110	17,804	91,174
2023	18,268	17,859	91,541
2024	18,388	17,962	91,981
2025	18,458	18,031	92,292
2026	18,603	18,148	92,677
2027	18,769	18,225	93,129
2028	18,917	18,380	93,677
2029	19,037	18,503	94,242
2030	19,266	18,637	94,852
2031	19,434	18,790	95,554
2032	19,655	18,962	96,216
2033	19,776	19,082	96,799
2034	20,013	19,200	97,419
2035	20,154	19,375	98,145
Avg. Annual Growth Rate	0.8%	0.6%	0.5%

Tables 12-E and 12-F differ from these values due to a 98 MW backstand contract with North Carolina Electric Municipal Co-op (NCEMC) throughout the study period.

FIGURE C-7

LOAD DURATION CURVE WITH ENERGY EFFICIENCY PROGRAMS & BEFORE DEMAND REDUCTION PROGRAMS



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D

ENERGY EFFICIENCY, DEMAND SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION

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APPENDIX D: ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION

CURRENT ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT PROGRAMS

DEC continues to pursue a long-term, balanced capacity and energy strategy to meet the future electricity needs of its customers. This balanced strategy includes a strong commitment to demand- side management (DSM) and energy efficiency (EE) programs, investments in renewable and emerging energy technologies, and state-of-the art power plants and delivery systems.

DEC uses EE and DSM programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: Energy efficiency (EE) programs that reduce energy consumption and demand-side management (DSM) programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs).

Following are the EE and DSM programs available through DEC as of December 31, 2019:

RESIDENTIAL EE PROGRAMS	NON-RESIDENTIAL EE PROGRAMS	RESIDENTIAL DSM PROGRAMS	NON-RESIDENTIAL DSM PROGRAMS
Energy Efficient Appliances and Devices	Non-Residential Smart $aver® Energy Efficient Products and Assessment	Power Manager	PowerShare®
Energy Efficiency Education	Non-Residential Smart $aver® Performance Incentive		Interruptible Service (IS)
Multi-Family Energy Efficiency	Small Business Energy Saver		Standby Generator (SG)
My Home Energy Report			EnergyWise® Business
Income-Qualified Energy Efficiency and Weatherization Assistance			
Energy Assessments			
Smart $aver® Energy Efficiency			

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ENERGY EFFICIENCY PROGRAMS

Energy Efficiency programs are typically non-dispatchable education or incentive-based programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant[1]) since the inception of these existing programs through the end of 2019 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a "Participant" in the information included below is based on the unit of measure for the specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEC's existing EE programs:

RESIDENTIAL EE PROGRAMS

ENERGY EFFICIENT APPLIANCES AND DEVICES PROGRAM

The Energy Efficient Appliances and Devices Program provides incentives to residential customers for installing energy efficient appliances and devices to drive reductions in energy usage. The program includes the following measures:

- Energy Efficient Lighting: DEC customers can take advantage of several program options and delivery mechanisms to improve lighting efficiency, including:

  a. The Free LED program offered free 9-watt A19 Light Emitting Diodes (LED) lamps to install in high-use fixtures through multiple channels to eligible customers. The on-demand ordering platform enabled eligible customers to request LEDs and have them shipped directly to their homes. This program concluded on June 30, 2020.

[1] "Gross of Free Riders" means that the impacts associated with the EE programs have not been reduced for the impact of Free Riders. "At the Plant" means that the impacts associated with the EE programs have been increased to include line losses.

b. The Duke Energy Savings Store is an extension of the on-demand ordering platform enabling eligible customers to purchase specialty bulbs and have them shipped directly to their homes. The Store offers a variety LEDs including; Reflectors, Globes, Candelabra, 3-Way, Dimmable and A-Line type bulbs. The program will no longer offer A-Line bulb incentives after 2020.

c. The Retail Lighting program partners with retailers and manufacturers across North and South Carolina to provide price markdowns on customer purchases of efficient lighting. Product mix includes Energy Star rated standard, reflector, and specialty LEDs, and fixtures. Participating retailers include a variety of channel types, including Big Box, DIY, Club, and Discount stores.

- Energy Efficient Water Heating and Usage: This program component encourages the adoption of low flow showerheads and faucet aerators, water heater insulation, and pipe wrap.

- Other Energy Efficiency Products and Services: Other energy efficient measures recently added to the program are Wi-Fi enabled smart thermostats, smart strips, and LED fixtures.

This program previously offered variable speed pool pump and heat pump water heaters, however, in late 2017 those measures were moved to the Residential Smart $aver® Energy Efficiency Program.

The tables below show actual program performance for all current and past program measures.

ENERGY EFFICIENT APPLIANCES AND DEVICES				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	63,803,127	2,476,134	323,988	84,366

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ENERGY EFFICIENCY EDUCATION PROGRAM

The Energy Efficiency Education Program is an energy efficiency program available to students in grades K-12 enrolled in public and private schools who reside in households served by Duke Energy Carolinas. The Program provides principals and teachers with an innovative curriculum that educates students about energy, resources, how energy and resources are related, ways energy is wasted and how to be more energy efficient. The centerpiece of the current curriculum is a live theatrical production performed by two professional actors that is focused on concepts such as energy, renewable fuels and energy efficiency.

Following the performance, students are encouraged to complete a home energy survey with their family to receive an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures to reduce home energy consumption and is available at no cost to student households at participating schools. Teachers receive supportive educational material for classroom and student take home assignments. The workbooks, assignments and activities meet state curriculum requirements.

ENERGY EFFICIENCY EDUCATION PROGRAM FOR SCHOOLS				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	234,148	57,948	10,307	3,859

MULTI-FAMILY ENERGY EFFICIENCY PROGRAM

The Multi-Family Energy Efficiency Program provides energy efficient lighting and water measures to reduce energy usage in eligible multi-family properties. The Program allows Duke Energy Carolinas to utilize an alternative delivery channel which targets multi-family apartment complexes. The measures are installed in permanent fixtures by the program administrator or the property management staff. The program offers LEDs including A-Line, Globes and Candelabra bulbs and energy efficient water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap.

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The tables below show actual program performance for current and past program measures.

MULTI-FAMILY ENERGY EFFICIENCY				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	2,854,090	144,261	15,397	10,708

MY HOME ENERGY REPORT PROGRAM

The My Home Energy Report (MyHER) Program provides residential customers with a comparative usage report that engages and motivates customers by comparing energy use to similar residences in the same geographical area based upon the age, size and heating source of the home. The report also empowers customers to become more efficient by providing them with specific energy saving recommendations to improve the efficiency of their homes. The actionable energy savings tips, as well as measure-specific coupons, rebates or other Company program offers that may be included in a customer's report are based on that specific customer's energy profile.

The program includes an interactive online portal that allows customers to further engage and learn more about their energy use and opportunities to reduce usage. Electronic versions of the My Home Energy Report are sent to customers enrolled on the portal. In addition, all MyHER customers with an email address on file with the Company receive an electronic version of their report monthly.

MY HOME ENERGY REPORT				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	1,339,152	328,439	91,387	79,435

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INCOME-QUALIFIED ENERGY EFFICIENCY AND WEATHERIZATION ASSISTANCE PROGRAM

The Income-Qualified Energy Efficiency and Weatherization Assistance Program consists of three distinct components designed to provide EE to different segments of its low-income customers:

- **Neighborhood Energy Saver (NES)** is available only to individually-metered residences served by Duke Energy Carolinas in neighborhoods selected by the Company, which are considered low-income based on third party and census data, which includes income level and household size. Neighborhoods targeted for participation in this program will typically have approximately 50% or more of the households with income below 200% of the poverty level established by the U.S. Government. This approach allows the Company to reach a larger audience of low-income customers than traditional government agency flow-through methods. The program provides customers with the direct installation of measures into the home to increase the EE and comfort level of the home. Additionally, customers receive EE education to encourage behavioral changes for managing energy usage and costs.

- **Weatherization and Equipment Replacement Program (WERP)** recognizes the existence of customers whose EE needs surpass the standard low-cost measure offerings provided through NES. WERP is available to income-qualified customers in the Duke Energy Carolinas service territory for existing, individually metered, single-family, condominiums, and mobile homes. Funds are available for weatherization measures and/or heating system replacement with a 15 or greater SEER heat pump. A full energy audit of the residence is used to determine the measures eligible for funding. Customers are placed into a tier based on energy usage, where Tier 1 provides up to $600 for energy efficiency services; while Tier 2 provides up to $4,000 for energy efficiency services, including insulation, thus allowing high energy users to receive more extensive weatherization measures.

- **The Refrigerator Replacement Program (RRP)** includes, but is not limited to, replacement of inefficient operable refrigerators in low income households. The program will be available to homeowners, renters, and landlords with income qualified tenants that own a qualified appliance. Income eligibility for RRP will mirror the income eligibility standards for the North Carolina Weatherization Assistance Program.

- **WERP** and **RRP** are delivered in coordination with State agencies that administer the state's weatherization programs.

LOW INCOME ENERGY EFFIENCY AND WEATHERIZATION ASSISTANCE PROGRAM				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	75,441	41,064	5,821	4,980

ENERGY ASSESSMENTS PROGRAM

The Energy Assessments Program provides eligible customers with a free in-home energy assessment, performed by a Building Performance Institute (BPI) certified energy specialist and designed to help customers reduce energy usage and save money. The BPI certified energy specialist completes a 60 to 90-minute walk through assessment of a customer's home and analyzes energy usage to identify energy savings opportunities. The energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The customer also receives a customized report that identifies actions the customer can take to increase their home's efficiency.

In addition to a customized report, customers receive an energy efficiency starter kit with a variety of measures that can be directly installed by the energy specialist. The kit includes measures such as energy efficient lighting, low flow shower head, low flow faucet aerators, outlet/switch gaskets, weather stripping and an energy saving tips booklet. Additional energy efficient bulbs are available to be installed by the auditor if needed.

RESIDENTIAL ENERGY ASSESSMENTS				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	197,969	80,591	11,941	2,470

Two previously offered Residential Energy Assessment measures were no longer offered in the new portfolio effective January 1, 2014. The historical performance of these measures through December 31, 2013 is included below.

PERSONALIZED ENERGY REPORT			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)	
		MWH ENERGY	PEAK SKW
December 31, 2019	86,333	24,502	2,790
ONLINE HOME ENERGY COMPARISON REPORT			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)	
		MWH ENERGY	PEAK SKW
December 31, 2019	12,902	3,547	387

SMART $AVER® ENERGY EFFICIENCY PROGRAM

The Smart $aver® Energy Efficiency Program offers measures that allow eligible Duke Energy Carolinas customers to take action and reduce energy consumption in their home. The Program offering provides incentives for the purchase and installation of eligible central air conditioner or heat pump replacements in addition to Quality Installations and Wi-Fi enabled Smart Thermostats when installed and programmed at the time of installation of the heating ventilation and air conditioning (HVAC) system. Program participants may also receive an incentive for attic insulation/air sealing, duct sealing, variable speed pool pumps, and heat pump water heaters.

The prescriptive and a-la-carte design of the program allows customers to implement individual, high priority measures in their homes without having to commit to multiple measures and higher price tags. A referral channel provides free, trusted referrals to customers seeking reliable, qualified contractors for their energy saving home improvement needs. This program previously offered HVAC Tune-Ups and Duct Insulation, however, those

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measures were removed due to no longer being cost-effective.

The tables below show actual program performance for all current and past program measures.

SMART SAVER ENERGY EFFICIENCY				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	171,758	93,689	28,016	9,352

NON-RESIDENTIAL EE PROGRAMS

NON-RESIDENTIAL SMART $AVER ENERGY EFFICIENT PRODUCTS AND ASSESSMENT PROGRAM

The Non-Residential Smart $aver Energy Efficient Products and Assessment Program provides incentives to DEP commercial and industrial customers to install high efficiency equipment in applications involving new construction and retrofits and to replace failed equipment.

Commercial and industrial customers can have significant energy consumption but may lack knowledge and understanding of the benefits of high efficiency alternatives. The Program provides financial incentives to help reduce the cost differential between standard and high efficiency equipment, offer a quicker return on investment, save money on customers' utility bills that can be reinvested in their business, and foster a cleaner environment. In addition, the Program encourages dealers and distributors (or market providers) to stock and provide these high efficiency alternatives to meet increased demand for the products.

The program provides incentives through prescriptive measures, custom measures and technical assistance.

- **Prescriptive Measures:** Customers receive incentive payments after the installation of certain high efficiency equipment found on the list of pre-defined prescriptive measures, including lighting; heating, ventilating and air conditioning equipment; and refrigeration measures and equipment. The program will no longer offer A-Line bulb incentives after 2020.

- **Custom Measures:** Custom measures are designed for customers with electrical energy saving projects involving more complicated or alternative technologies, whole-building projects, or those measures not included in the Prescriptive measure list. The intent of the Program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance. Unlike the Prescriptive portion of the program, all Custom measure incentives require pre-approval prior to the project implementation. The program will no longer offer A-Line bulb incentives after 2020.

- **Energy Assessments and Design Assistance:** Incentives are available to assist customers with energy studies such as energy audits, retro commissioning, and system-specific energy audits for existing buildings and with design assistance such as energy modeling for new construction. Customers may use a contracted Duke Energy vendor to perform the work or they may select their own vendor. Additionally, the Program assists customers who identify measures that may qualify for Smart $aver Incentives with their applications. Pre-approval is required. In 2019, the program modified its approach to a Virtual Energy Assessment utilizing an energy modeling software to complete the assessment in 2-3 weeks at a lower cost.

NON-RESIDENTIAL SMART SAVER ENERGY EFFICIENCY PRODUCTS AND ASSESSMENT				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	30,471,766	2,528,566	421,586	165,199

NOTE: Participants have different units of measure.

NON-RESIDENTIAL SMART $AVER PERFORMANCE INCENTIVE PROGRAM

The Non-Residential Smart $aver® Performance Incentive Program offers financial assistance to qualifying commercial, industrial and institutional customers to enhance their ability to adopt and install cost-effective electrical energy efficiency projects. The Program encourages the installation of new high efficiency equipment in new and existing nonresidential establishments as well as efficiency-related repair activities designed to maintain or enhance

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efficiency levels in currently installed equipment. Incentive payments are provided to offset a portion of the higher cost of energy efficient installations that are not eligible under either the Smart $aver® Prescriptive or Custom programs. The Program requires pre-approval prior to project initiation.

The types of projects covered by the Program include projects with some combination of unknown building conditions or system constraints, or uncertain operating, occupancy, or production schedules. The intent of the Program is to broaden participation in non-residential efficiency programs by being able to provide incentives for projects that previously were deemed too unpredictable to calculate an acceptably accurate savings amount, and therefore ineligible for incentives. This Program provides a platform to understand new technologies better. Only projects that demonstrate that they clearly reduce electrical consumption and/or demand are eligible for incentives.

The key difference between this program and the Non-Residential Smart $aver Energy® Custom program is that Performance Incentive participants get paid based on actual measure performance and involves the following two step process.

- ***Incentive #1:*** For the portion of savings that are expected to be achieved with a high degree of confidence, an initial incentive is paid once the installation is complete.
- ***Incentive #2:*** After actual performance is measured and verified, the performance-based part of the incentive is paid. The amount of the payout is tied directly to the savings achieved by the measures.

NON-RESIDENTIAL SMART SAVER PERFORMANCE INCENTIVE				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	156	9,692	695	745

SMALL BUSINESS ENERGY SAVER PROGRAM

The Small Business Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within qualifying non-residential customer facilities. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The program is available to existing non-residential customers that are not opted-out of the Company's EE/DSM Rider and have an average annual demand of 180 kW or less per active account.

Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Carolinas. The customer makes the final determination of which measures will be installed after receiving the results of the energy assessment. The Company-authorized vendor schedules the installation of the energy efficiency measures at a convenient time for the customer, and electrical subcontractors perform the work.

SMALL BUSINESS ENERGY SAVER				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	342,704,915	386,003	70,787	33,129

DEMAND-SIDE MANAGEMENT PROGRAMS

RESIDENTIAL

POWER MANAGER®

The Power Manager® provides residential customers a voluntary demand response program that allows Duke Energy Carolinas to limit the run time of participating customers' central air conditioning (cooling) systems to reduce electricity demand. Power Manager® may be used to completely interrupt service to the cooling system when the Company experiences capacity

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problems. In addition, the Company may intermittently interrupt (cycle) service to the cooling system. For their participation in Power Manager®, customers receive bill credits during the billing months of July through October.

Power Manager® provides DEC with the ability to reduce and shift peak loads, thereby enabling a corresponding deferral of new supply-side peaking generation and enhancing system reliability.

Participating customers are impacted by (1) the installation of load control equipment at their residence, (2) load control events which curtail the operation of their air conditioning unit for a period of time each hour, and (3) the receipt of bill credits from DEC in exchange for allowing DEC the ability to control their electric equipment.

POWER MANAGER©			
CUMULATIVE AS OF:	PARTICIPANTS (CUSTOMERS)	DEVICES (SWITCHES)	SUMMER 2019 CAPABILITY (MW)
December 31, 2019	238,057	286,473	569

The following table shows Power Manager® program activations that were for the general population from June 1, 2018 through December 31, 2019.

POWER MANAGER© PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
07/15/2019	4:00 PM	6:00 PM	120	275
08/09/2019	4:30 PM	5:00 PM	30	302
09/09/2019	4:00 PM	6:00 PM	120	183
09/12/2019	3:00 PM	6:00 PM	180	230
09/26/2019	4:00 PM	6:00 PM	120	227

Power Manager® added a summer cooling Bring Your Own Thermostat (BYOT) option in late December 2019. Customer acquisition for this program option year to date through June

2020 is 14,500 participants. No activations of this program option have been administered through June 2020.

NON-RESIDENTIAL

DEMAND RESPONSE – CURTAILABLE PROGRAMS

The DEC non-residential demand response portfolio consists of a combination of programs that rely either on the customer's ability to respond to a utility-initiated notification or on receipt of a signal to control customer equipment, including small business thermostats. Customers are offered ongoing incentives commensurate to the amount of load they are capable of curtailing.

The recent Nexant Market Potential Study forecasted minimal summer and winter non-residential DSM growth opportunities in the Carolinas, particularly for the small and medium business segment. Further, given the expected impact of the Enhanced scenario's doubling of incentives on program cost-effectiveness and future DSM rate adjustments, the Base scenario would be considered more applicable for the large non-residential segment. The large business demand response programs are actively marketed to all customer segments that are known to possess the flexibility to curtail load and have demands high enough to comply with program minimums, which means that there is a simultaneous effort to maximize both winter and summer resources. Although they provide for flexibility in contracting for different winter and summer commitments due to seasonal variations in customers' loads and operational characteristics, the programs are designed to incent participants to provide curtailable demand year-round. This allows for availability of the programs even in off-peak months when scheduled generation maintenance, in conjunction with unseasonable temperatures or other weather events, could lead to the need for demand-side management resources.

Duke Energy Carolinas' current curtailable programs include:

PowerShare® is a non-residential curtailment program consisting of four options: an emergency-only option for curtailable load (PowerShare® Mandatory), an emergency-only option for load curtailment using on-site generators (PowerShare® Generator), and an economic-based voluntary option (PowerShare® Voluntary).

PowerShare® Mandatory: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Participants also receive energy credits for the load curtailed during events. Customers enrolled may also be enrolled in PowerShare® Voluntary and eligible to earn additional credits.

POWERSHARE© MANDATORY			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	147	327	307

The following table shows PowerShare® Mandatory program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

POWERSHARE® MANDATORY PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION (@GEN)
1/2/2018	7:00 am	10:00 am	180	273
1/7/2018	7:30 am	10:30 am	180	203

PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail (i.e. transfer to their on-site generator) during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.

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POWERSHARE® GENERATOR STATISTICS			
AS OF:	PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	10	10.5	9.9

The following table shows PowerShare® Generator program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

POWERSHARE® GENERATOR PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION (@GEN)
1/2/2018	7:00 am	10:00 am	180	9
1/7/2018	7:30 am	10:30 am	180	7

PowerShare® Voluntary: Enrolled customers will be notified of pending emergency or economic events and can log on to a website to view a posted energy price for that event. Customers will then have the option to participate in the event and will be paid the posted energy credit for load curtailed. Since this is a voluntary event program, no capacity benefit is recognized for this program and no capacity incentive is provided. The values below represent participation in PowerShare® Voluntary only and do not double count the participants in PowerShare® Mandatory that also participate in PowerShare® Voluntary.

POWERSHARE® VOLUNTARY			
AS OF:	PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	0	N/A	N/A

There were no PowerShare® Voluntary program activations from January 1, 2018 through December 31, 2019.

Interruptible Power Service (IS): (North Carolina Only) Participants agree contractually to reduce their electrical loads to specified levels upon request by DEC. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

IS PROGRAM			
AS OF:	PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	42	128	113

The following table shows IS program activations that were <u>not</u> for testing purposes from January 1, 2018 through December 31, 2019.

IS PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION (@GEN)
1/2/2018	7:00 AM	10:00 AM	180	95
1/7/2018	7:30 AM	10:30 AM	180	69

Standby Generator Control (SG): (North Carolina Only) Participants agree contractually to transfer electrical loads from the DEC source to their standby generators upon request of the Company. The generators in this program do not operate in parallel with the DEC system and therefore, cannot "backfeed" (i.e., export power) into the DEC system.

SG PROGRAM			
AS OF:	PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	13	10	10

The following table shows SG program activations that were <u>not</u> for testing purposes from January 1, 2018 through December 31, 2019.

SG PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION (@GEN)
1/2/2018	7:00 AM	10:00 AM	180	9
1/7/2018	7:30 AM	10:30 AM	180	8.5

EnergyWise® Business: This is both an energy efficiency and demand response program for non-residential customers that allows DEC to reduce the operation of participants' air conditioning units to mitigate system capacity constraints and improve reliability of the power grid.

Program participants can choose between a Wi-Fi thermostat or load control switch that will be professionally installed for free on each air conditioning or heat pump unit. In addition to equipment choice, participants can also select the cycling level they prefer (i.e., a 30%, 50% or 75% reduction of the normal on/off cycle of the unit). During a conservation period, DEC will send a signal to the thermostat or switch to reduce the on time of the unit by the cycling percentage selected by the participant. Participating customers will receive a $50 annual bill credit for each unit at the 30% cycling level, $85 for 50% cycling, or $135 for 75% cycling. Participants that have a heat pump unit with electric resistance emergency/back up heat and choose the thermostat can also participate in a winter option that allows control of the emergency/back up heat at 100% cycling for an additional $25 annual bill credit. Participants will also be allowed to override two conservation periods per year.

Participants choosing the thermostat will be given access to a portal that will allow them to set schedules, adjust the temperature set points, and receive energy conservation tips and communications from DEC. In addition to the portal access, participants will also receive conservation period notifications, so they can adjust their schedules or notify their employees of the upcoming conservation periods.

ENERGYWISE® BUSINESS PROGRAM				
CUMULATIVE AS OF:	PARTICIPANTS*	MW CAPABILITY (@GEN)		MWH ENERGY SAVINGS (@GEN)
		SUMMER	WINTER	
December 31, 2019	12,885	12.1	2.6	635

* Number of participants represents the number of measures under control.

The following table shows **EnergyWise® Business** program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

ENERGYWISE® BUSINESS PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
8/28/2018	4:00 pm	6:00 pm	120	7.5
7/2/2019	4:00 pm	6:00 pm	120	9.9
7/17/2019	4:00 pm	6:00 pm	2.0	9.9
9/12/2019	4:00 pm	6:00 pm	2.0	10.5

DISCONTINUED DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

Since the last biennial Resource Plan filing, DEC discontinued the following DSM/EE programs:

- **PowerShare CallOption** – Due to a lack of customer interest, DEC closed the PowerShare CallOption (Rider PSC) program in North Carolina effective January 31, 2018, pursuant to an NCUC Order issued in Docket E-7, Sub 1130, dated August 23, 2017. The Company gained approval to close the program in South Carolina effective August 31, 2018, through PSC Order 2018-581 under Docket 2013-298-E.

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FUTURE EE AND DSM PROGRAMS

DEC is continually seeking to enhance its EE and DSM portfolio by: (1) adding new programs or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new M&V results, and (3) other EE pilots.

DEC plans to evaluate and consider the addition of cost-effective winter measures to the **Power Manager®** program in 2020. These measures include winter BYOT, water heating control, and heat pump heat strip control.

Potential new programs and/or measures will be reviewed with the DSM Collaborative then submitted to the Public Utility Commissions as required for approval.

EE AND DSM PROGRAM SCREENING

The Company uses the DSMore model to evaluate the costs, benefits, and risks of EE and DSM programs and measures. DSMore is a financial analysis tool designed to estimate of the capacity and energy values of EE and DSM measures at an hourly level across distributions of weather conditions and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing EE and DSM measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency and demand-side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test, Rate Impact Measure Test, Total Resource Cost Test and Participant Test. DSMore provides the results of those tests for any type of EE or DSM program.

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any State, Federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of cost-effective DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Program Forecasts:

FORECAST METHODOLOGY

In 2019, DEC commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final reports (one for South Carolina and one for North Carolina) were prepared by Nexant Inc. and issued in May 2020 with a final revision completed in June 2020.

The Nexant study results are suitable for IRP purposes and for use in long-range system planning models. This study also helps to inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. This study did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted as well as the timing of the introduction of those programs. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. The study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from DEC program managers and EE planners, feedback from the DSM Collaborative and with the possible assistance of implementation contractors.

The Nexant market potential study (MPS) included projections of Energy Efficiency impacts over a 25-year period for Base, Enhanced and Avoided Energy Cost Sensitivity Scenario, which were used in conjunction with expected EE savings from DEC's five-year program plan to develop the Base, High and Low Case EE savings forecasts for this IRP.

The Base Case EE savings forecast represents a merging of the projected near-term savings from DEC's five-year plan (2020-2024) with the long-term savings from the Nexant MPS (2030-onward). Savings during the five-year period (2025-2029) between the two sets of projections represents a merging of the two forecasts to ensure a smooth transition.

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The High Case EE savings forecast was developed using the same process as the Base case, however; for the Nexant MPS portion of the forecast, the difference between the Avoided Energy Cost Sensitivity and Base Scenarios for all years was added to the Enhanced Case forecast. This method captures the higher EE savings resulting from both the higher avoided energy cost assumptions as well as from increased customer incentives in the Enhanced case.

Finally, the Low Case was developed by applying a reduction factor to the Base Case forecast. Additionally, the cumulative savings projections for the Base, High and Low Case EE forecasts included an assumption that when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts, a process defined as "rolloff".

The tables below provide the projected MWh load impacts for the Base, High and Low Case forecasts of all DEC EE programs implemented since the approval of the save-a-watt recovery mechanism in 2009 on a Net of Free Riders basis. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning period, however, the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings since the inception of the EE programs in 2009 through the end of 2019, which accounts for approximately an additional 5,200 gigawatt-hour (GWh) of net energy savings. The following forecasts are presented without the effects of "rolloff":

PROJECTED MWH IMPACTS OF EE PROGRAMS
BASE CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009
2009-19		5,200,658
2020	735,249	5,935,907
2021	1,114,552	6,315,210
2022	1,489,213	6,689,871
2023	1,845,095	7,045,753
2024	2,188,158	7,388,816
2025	2,507,961	7,708,619
2026	2,790,708	7,991,366
2027	3,036,400	8,237,058
2028	3,245,037	8,445,695
2029	3,416,618	8,617,276
2030	3,551,144	8,751,802
2031	3,670,799	8,871,457
2032	3,787,171	8,987,829
2033	3,900,360	9,101,018
2034	4,011,444	9,212,102
2035	4,120,603	9,321,261

*The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.

PROJECTED MWH IMPACTS OF EE PROGRAMS
HIGH CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009
2009-19		5,200,658
2020	735,249	5,935,907
2021	1,152,397	6,353,055
2022	1,564,439	6,765,097
2023	1,955,823	7,156,481
2024	2,333,106	7,533,764
2025	2,686,048	7,886,706
2026	3,000,854	8,201,512
2027	3,277,523	8,478,181
2028	3,516,056	8,716,714
2029	3,716,453	8,917,111
2030	3,878,713	9,079,371
2031	4,024,353	9,225,011
2032	4,165,073	9,365,731
2033	4,301,216	9,501,874
2034	4,434,129	9,634,787
2035	4,564,305	9,764,963

*The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.

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PROJECTED MWH IMPACTS OF EE PROGRAMS
LOW CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009
2009-19		5,200,658
2020	551,437	5,752,095
2021	835,914	6,036,572
2022	1,116,910	6,317,568
2023	1,383,821	6,584,479
2024	1,641,118	6,841,776
2025	1,880,970	7,081,628
2026	2,093,031	7,293,689
2027	2,277,300	7,477,958
2028	2,433,777	7,634,435
2029	2,562,463	7,763,121
2030	2,663,358	7,864,016
2031	2,753,100	7,953,758
2032	2,840,378	8,041,036
2033	2,925,270	8,125,928
2034	3,008,583	8,209,241
2035	3,090,452	8,291,110

*The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.

The MW impacts from the EE programs are included in the Load Forecasting section of this IRP. The tables below provide the projected winter and summer peak MW load impacts of all current and projected DEC DSM programs.

PROJECTED MW LOAD IMPACTS OF DSM PROGRAMS

	WINTER PEAK MW REDUCTION					
YEAR	POWER MANAGER	POWERSHARE MANDATORY	IS	SG	ENERGWISE BUSINESS	TOTAL SUMMER PEAK
2020	0	315	120	10	2	446
2021	0	347	98	2	2	449
2022	4	337	93	2	3	438
2023	6	340	88	2	3	439
2024	8	343	84	2	4	441
2025	13	345	80	1	4	444
2026	19	345	77	1	4	446
2027	28	345	77	1	4	455
2028	40	345	77	1	4	467
2029	56	345	77	1	4	484
2030	77	345	77	1	4	504
2031	101	345	77	1	4	529
2032	128	345	77	1	4	555
2033	154	345	77	1	4	582
2034	179	345	77	1	4	606
2035	199	345	77	1	4	627

NOTE: For DSM programs, Gross and Net are the same.

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PROJECTED MW LOAD IMPACTS OF DSM PROGRAMS

	SUMMER PEAK MW REDUCTION					
YEAR	POWER MANAGER	POWERSHARE MANDATORY	IS	SG	ENERGWISE BUSINESS	TOTAL SUMMER PEAK
2020	578	373	108	2	23	1084
2021	590	359	102	2	29	1082
2022	590	362	97	2	34	1086
2023	591	366	92	2	39	1090
2024	591	369	88	2	46	1096
2025	592	370	84	2	46	1094
2026	593	370	82	2	46	1093
2027	595	370	82	2	46	1095
2028	597	370	82	2	46	1097
2029	600	370	82	2	46	1100
2030	603	370	82	2	46	1103
2031	607	370	82	2	46	1107
2032	611	370	82	2	46	1111
2033	615	370	82	2	46	1115
2034	619	370	82	2	46	1119
2035	621	370	82	2	46	1122

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EE SAVINGS VARIANCE SINCE LAST IRP

In response to Order number 7 in the NCUC Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRP's, the Base Portfolio EE savings forecast of MW and MWh was compared to the 2018 IRP and the cumulative achievements projected in the 2020 IRP at year 2035 of the forecast are approximately 16.7% lower than the cumulative achievements in the 2018 IRP for the same time period as shown in the table below.

For the next 5-years, the Company's projected energy efficiency program adoption is expected to achieve savings within 10% of projections for the same period in the 2018 IRP. However, longer term, the new market potential study (filed as Attachment V of this IRP) has projected that most of the programs which pass economic screening will have reached maturity over the next 10-years resulting in lower future adoption rates in comparison to the previous MPS conducted in 2016. As can be seen in the exhibit below, the near-term variance is positive but decreases in magnitude over time, ultimately becoming negative in the final 7-years of the forecast period based on the projections in the MPS.

The Company will continue to evaluate the results of the MPS in conjunction with the EE/DSM Collaborative and continue to investigate new efficiency measures or programs which may enhance future projections.

BASE CASE COMPARISON TO 2018 DEC IRP					
	2018 IRP		2020 IRP		
	ANNUAL MWH LOAD REDUCTION - NET		ANNUAL MWH LOAD REDUCTION - NET		
YEAR	INCLUDING MEASURES ADDED IN 2018 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009	% CHANGE FROM 2018 TO 2020 IRP
2018	457,007	4,553,221			
2019	887,403	4,983,616		5,200,658	4.4%
2020	1,300,965	5,397,178	735,249	5,935,907	10.0%
2021	1,679,020	5,775,233	1,114,552	6,315,210	9.3%
2022	2,053,771	6,149,984	1,489,213	6,689,871	8.8%
2023	2,429,142	6,525,356	1,845,095	7,045,753	8.0%
2024	2,805,135	6,901,349	2,188,158	7,388,816	7.1%
2025	3,181,749	7,277,963	2,507,961	7,708,619	5.9%
2026	3,558,985	7,655,198	2,790,708	7,991,366	4.4%
2027	3,936,841	8,033,054	3,036,400	8,237,058	2.5%
2028	4,315,318	8,411,532	3,245,037	8,445,695	0.4%
2029	4,696,455	8,792,668	3,416,618	8,617,276	-2.0%
2030	5,081,308	9,177,522	3,551,144	8,751,802	-4.6%
2031	5,471,391	9,567,605	3,670,799	8,871,457	-7.3%
2032	5,869,066	9,965,280	3,787,171	8,987,829	-9.8%
2033	6,270,015	10,366,228	3,900,360	9,101,018	-12.2%
2034	6,678,531	10,774,744	4,011,444	9,212,102	-14.5%
2035	7,093,543	11,189,756	4,120,603	9,321,261	-16.7%

PROGRAMS EVALUATED BUT REJECTED

Duke Energy Carolinas has not rejected any cost-effective programs as a result of its EE and DSM program screening.

INTEGRATED VOLT-VAR CONTROL

PROGRAM DESCRIPTION

Duke Energy Carolinas (DEC) is beginning implementation of an Integrated Volt-Var Control (IVVC) project that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Carolinas distribution system. DEC would primarily operate IVVC in the form of Conservation Voltage Reduction (CVR). Integrated Voltage/VAR Control (IVVC) is the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. This allows the distribution system to operate as efficiently as possible without violating load and voltage constraints, while supporting the reactive power needs of the bulk power system. IVVC can be implemented through various Substation and Distribution projects included within the Duke Energy Carolinas (DEC) IVVC Evaluation. Currently, communication with and control of substation voltage regulation, substation capacitors, and distribution line voltage regulators on the DEC system is minimal. Additionally, distribution line capacitors have communications, but not remote control, capabilities. Primary projects to install communications and control infrastructure include Substation Voltage Regulator Control Replacement, Substation Capacitor Control Replacement, Distribution Line Voltage Regulator Control Replacement, Distribution Line Capacitor Control Replacement, possible installation of End of Line Medium Voltage Sensors, and two-way communications implementation into these substation and distribution line devices. New Distribution Line Voltage Regulator and Capacitor additions are also possible. Other proposed projects, such as the Self Optimized Grid, overlap in providing some of the infrastructure and capabilities necessary to enable IVVC. Therefore, Duke Energy Carolinas could take advantage of resource and scope opportunities from all the projects combined to make IVVC possible.

IVVC can dynamically optimize the control of substation and distribution devices, resulting in a flattening of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by integrating substation and distribution line voltage regulators and capacitors into the Distribution Management System (DMS) with two-way communications, automating their operation. The DMS continuously monitors the conditions on the controlled circuits and maintains the desired voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage [conservation voltage reduction (CVR)] at the substation results in a reduction of system loading, creating the benefit of decreased generation. CVR is an operational mode of Volt Var Optimization (VVO) that supports voltage reduction and energy conservation. This provides fuel savings to customers and reduced emissions from the avoided generation.

IVVC provides increased visibility into the status and condition of substation and field devices such as capacitor banks, voltage regulators, and transformer load-tap changers. This added visibility and enhanced voltage control will help manage the integration of distributed energy resources (i.e. solar) by improving the grid's ability to respond to intermittency. Access to additional system data will aid grid operators in the daily operation of the distribution grid and promote reliability. CVR functionality would target a potential 2% voltage reduction on the circuits and substations within the scope of implementation. This scope accounts for approximately 50% of the total circuits and substations across DEC, which account for approximately 70% of current base load. Assuming an average CVR factor of 0.7 (CVR Factor = % Load Reduction / % Voltage Reduction) this 2% voltage reduction is estimated to result in a 1.4% load reduction for enabled circuits. There may be cases where a variation in voltage could impact customers with large motors sensitive to voltage control. The DMS system can be designed to manage distribution circuits serving loads with voltage sensitivities, reducing these impacts. It is expected that CVR functionality would be utilized for the majority of the year. However, CVR mode would provide less demand reduction capability than peak shaving mode. To maximize operational flexibility and value, the IVVC system will also have peak shaving capability and emergency modes of operation. The software within the future enterprise DMS platform will enable IVVC to operate in various modes to provide further customer benefit.

BENEFITS

- Reduced distribution line losses due to lower overall voltage
- More efficient grid due to lower line losses and reduced reactive power
- Less generation fuel consumed and lower emissions due to grid efficiencies
- Integrated control of capacitor banks provides greater ability to reduce reactive power, resulting in less apparent load on the system
- Less peak load on the grid could result in a reduced need to build additional peaking generation
- Optimized control of Volt-VAR devices improves the grid's ability to respond to intermittency
- Helps to manage integration of distributed energy resources

IVVC is part of the proposed Duke Energy Carolinas Grid Improvement Plan. The deployment of an IVVC program for DEC is anticipated to take approximately 4-years. IVVC will become functional upon full integration of the control system, substation components, and distribution line components.

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DEC (NORTH CAROLINA & SOUTH CAROLINA) INTEGRATED VOLT VAR CONTROL (IVVC) ANNUAL ESTIMATED ENERGY REDUCTION (KWH) OPERATING CONSERVATION VOLTAGE REDUCTION (CVR) 90% OF THE HOURS*		
YEAR	IVVC DEPLOYMENT (%)	TOTAL REDUCTION (KWH)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	30,607,478
2024	20%	61,765,891
2025	100%	311,608,922
2026	100%	314,413,403
2027	100%	317,243,123
2028	100%	320,098,311
2029	100%	322,979,196
2030	100%	325,886,009
2031	100%	328,818,983
2032	100%	331,778,354
2033	100%	334,764,359
2034	100%	337,777,238
2035	100%	340,817,233

*(Energy reduction does not account for system losses upstream of distribution retail substations).

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DEC (NORTH CAROLINA & SOUTH CAROLINA)
INTEGRATED VOLT VAR CONTROL (IVVC)
ANNUAL ESTIMATED DEMAND REDUCTION (KW)*

Year Round Conservation Voltage Reduction (CVR) Mode Approximately 90% of the Hours

YEAR	IVVC DEPLOYMENT (%)	TOTAL REDUCTION (KW)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	12,713
2024	20%	25,655
2025	100%	129,431
2026	100%	130,596
2027	100%	131,771
2028	100%	132,957
2029	100%	134,154
2030	100%	135,361
2031	100%	136,580
2032	100%	137,809
2033	100%	139,049
2034	100%	140,301
2035	100%	141,563

*(Demand reduction does not account for system losses upstream of distribution retail substations).

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Peak-Shaving Mode Approximately <10% of the Hours

YEAR	IVVC DEPLOYMENT (%)	TOTAL REDUCTION (KW)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	16,951
2024	20%	34,207
2025	100%	172,575
2026	100%	174,128
2027	100%	175,695
2028	100%	177,277
2029	100%	178,872
2030	100%	180,482
2031	100%	182,106
2032	100%	183,745
2033	100%	185,399
2034	100%	187,067
2035	100%	188,751

*(Demand reduction does not account for system losses upstream of distribution retail substations).

VOLT - VAR OPTIMIZATION TERMINOLOGY

VVO	*Volt-VAR Optimization*	Management of Voltage levels and Reactive Power at optimal levels to operate the grid more efficiently
IVVC	*Integrated Volt-VAR Control*	Full coordination and configuration of intelligent field devices and a management/control system (e.g., DMS, DSCADA) that uses grid data to achieve efficient grid operation while maintaining distribution voltages within acceptable operating limits
DMS	*Distribution Management System*	Primary information system used to monitor, analyze, and control the distribution grid efficiently and reliably
DSDR	*Distribution System Demand Response*	Operational mode of VVO that supports peak shaving and emergency MW *(demand)* reduction (alternative to building peaking plant generation)
CVR	*Conservation Voltage Reduction*	Operational mode of VVO that supports 24/7 voltage reduction and energy conservation (alternative to building base load generation)

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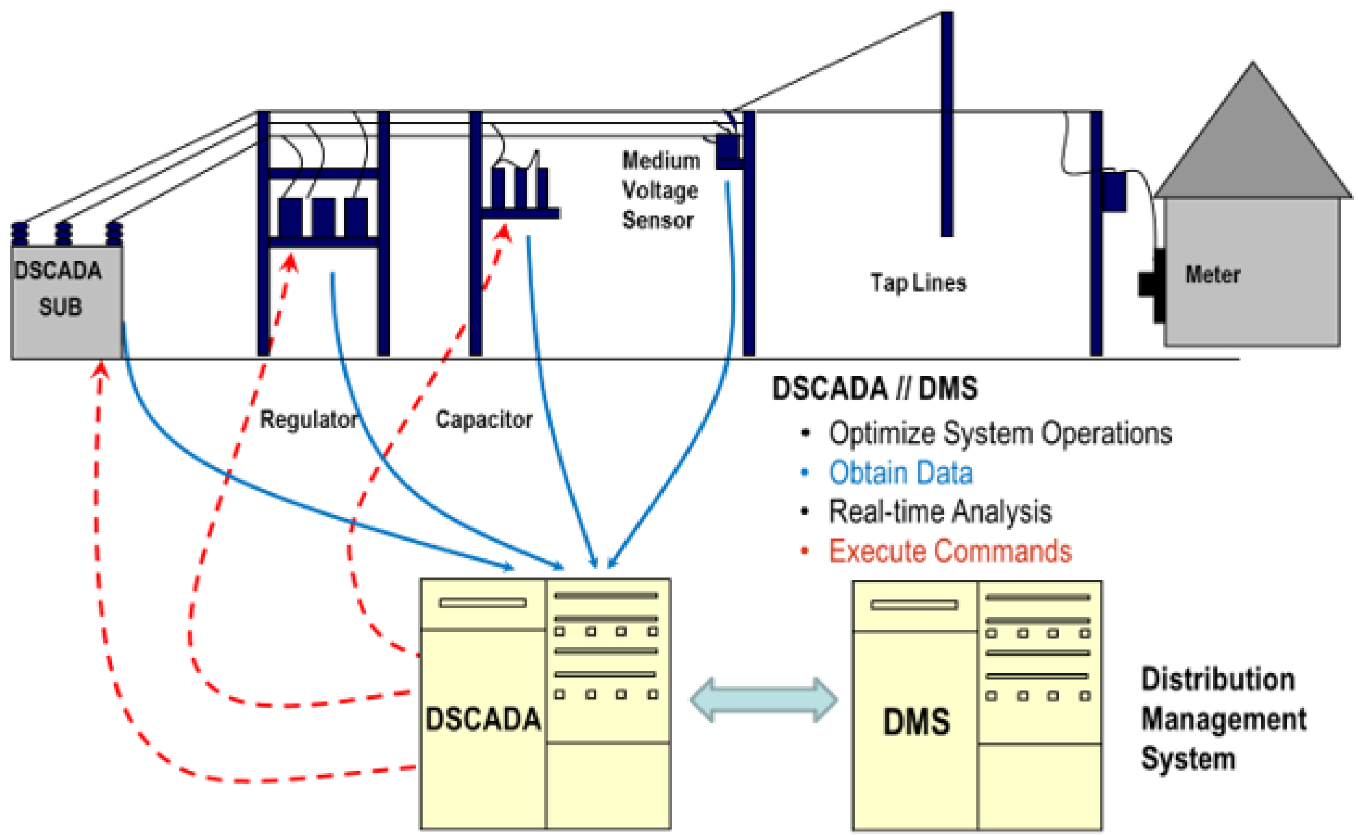
DUKE ENERGY CAROLINAS

DEC VOLT VAR CONTROL



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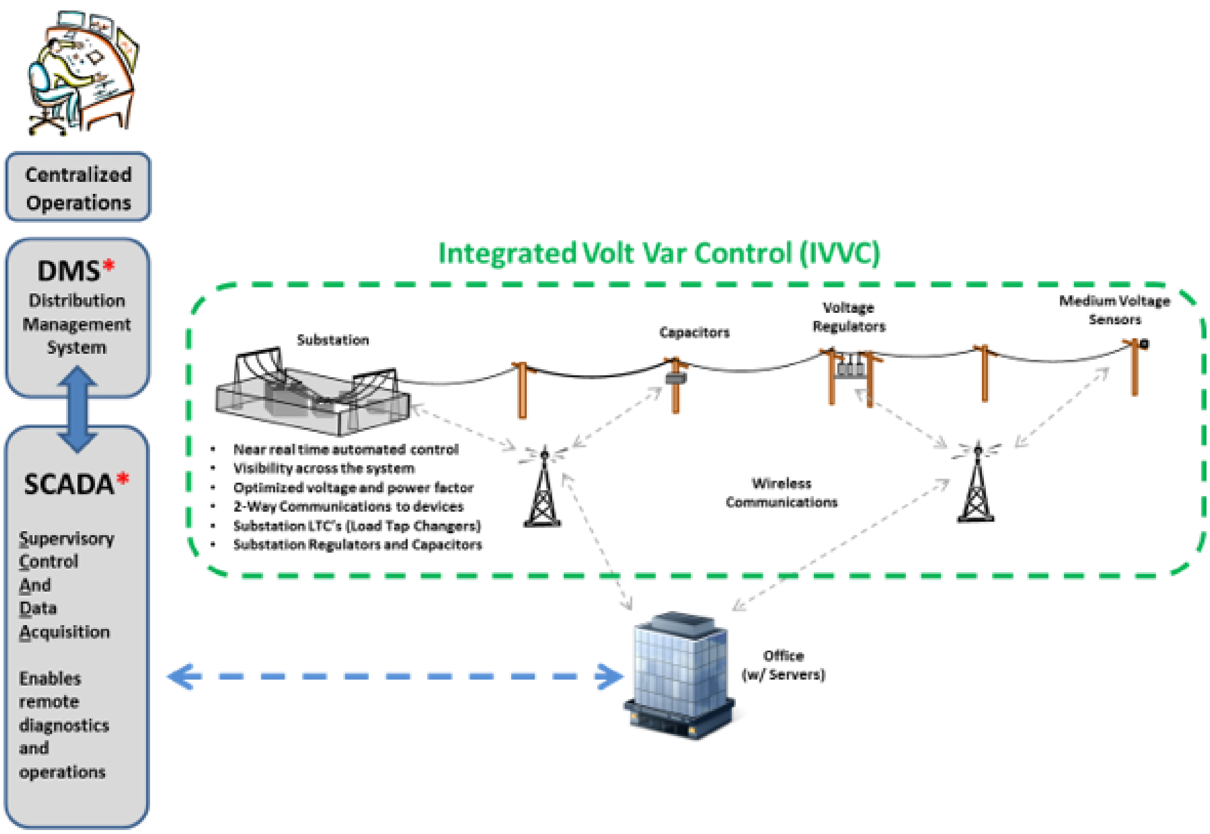
"HIGH LEVEL" CONCEPTUAL DESIGN



- DSM & SCADE already exists and is not in scope of this project.
- Devices will be integrated into the existing DMS/SCADA

RENEWABLE ENERGY STRATEGY / FORECAST

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APPENDIX E: RENEWABLE ENERGY STRATEGY/FORECAST

The growth of renewable generation in the United States continued in 2019. According to EIA, in 2019, 9.1 GW of wind and 5.3 GW of utility-scale solar capacity were installed nationwide. The EIA also estimates 3.7 GW of small scale solar was added as well.[1] Notably, U.S. annual energy consumption from renewable sources exceeded coal consumption for the first time since before 1885.[2]

North Carolina ranked sixth in the country in solar capacity added,and first in additions of solar plants greater than 2 MW, in 2019 and remains second behind only California in total solar capacity online, while South Carolina ranked seventh in solar capacity added in 2019.[3][4] Duke Energy's compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), the South Carolina Distributed Energy Resource Program (SC DER or SC Act 236), the Public Utility Regulatory Policies Act (PURPA) as well as the availability of the Federal Investment Tax Credit (ITC) were key factors behind the high investment in solar.

RENEWABLE ENERGY OUTLOOK FOR DUKE ENERGY IN THE CAROLINAS

The future is bright for opportunities for continued renewable energy development in the Carolinas as both states have supportive policy frameworks and above average renewable resource availability, particularly for solar. The Carolinas also benefits from substantial local expertise in developing and interconnecting large scale solar projects and the region will benefit from such a concentration of skilled workers. Both states are supporting future renewable energy development via two landmark pieces of legislation, HB 589 in North Carolina (2017) and Act 62 in South Carolina (2019). These provide opportunities for increased renewable energy, particularly for utility customer programs for both large and small customers who want renewable energy. These programs have the potential to add significant renewable capacity that will be additive to the historic reliance on administratively-established standard offer procurement under PURPA in the Carolinas. Furthermore, the Companies'

[1] All renewable energy GW/MW represent GW/MW-AC (alternating current) unless otherwise noted.
[2] https://www.eia.gov/todayinenergy/detail.php?id=43895.
[3] https://www.seia.org/states-map.
[4] https://www.eia.gov/electricity/data/eia860M/; February month end data.

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pending request to implement Queue Reform—a transition from a serial study interconnection process to a cluster study process—will create a more efficient and predictable path to interconnection for viable projects, including those that are identified through any current or future procurement structures. It is also worth noting that that there are solar projects that appear to be moving forward with 5-year administratively-established fixed price PURPA contracts and additional solar projects that will likely be completed as part of the transition under Queue Reform.

SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS

DRIVERS FOR INCREASING RENEWABLES IN DEC

The implementation of NC HB 589, and the passage of SC Act 62 in SC are significant to the amount of solar projected to be operational during the planning horizon. Growing customer demand, the Federal ITC, and declining installed solar costs continue to make solar capacity the Company's primary renewable energy resource in the 2020 IRP. However, achieving the Company's goal of net-zero carbon emissions by 2050 will require a diverse mix of renewable, and other zero-emitting, load following resources. Wind generation, whether onshore wind generated in the Carolinas or wheeled in from other regions of the country, or offshore wind generated off the coast of the Carolinas, may become a viable contributor to the Company's resource mix over the planning horizon.

The following key input assumptions regarding renewable energy were included in the 2020 IRP:

- Through existing legislation such as NC HB589 and opportunities under SC Act 62, along with materialization of existing projects in the distribution and transmission interconnection queues, installed solar capacity increases in DEC from 966 MW in 2021 to 3,493 MW in 2035 with approximately 185 MW of usable AC storage coupled with solar included prior to incremental solar added economically during the planning process.

- Additional solar and solar coupled with storage was available to be selected by the capacity expansion model to provide economic energy and capacity. Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 300 MW per year over the planning horizon in DEC.

- Up to 150 MW of onshore Carolinas wind generation, assumed to be located in the central Carolinas, could be selected by the capacity expansion model annually to provide a diverse source of economic energy and capacity.
- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases.
- Achievement of the SC Act 236 goal of 160 MW of solar capacity located in DEC.
- Implementation of NC HB 589 and SC Act 62 and continuing solar cost declines drive solar capacity growth above and beyond NC REPS requirements.

NC HB 589 COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE)

NC HB 589 established a competitive solicitation process, known as the Competitive Procurement of Renewable Energy (CPRE), which specified for the addition of up to 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period ending November 2021. On July 10, 2018, Duke issued a request for bids for the first tranche of CPRE, requesting 600 MW in DEC and 80 MW in DEP. On April 9, 2019 the independent administrator selected 12 projects totaling 515 MW in DEC and two projects totaling 83 MW in DEP. Eleven of the DEC projects totaling 465 MW signed PPA's, but subsequently, one project dropped out and will not move forward, bringing the total capacity procured to 435 MW. Nine of the projects will be located within North Carolina (415 MW), one will be in South Carolina (20 MW), and the projects will all be interconnected to the transmission system. Two of the solar projects selected will be owned by Duke Energy Carolinas and three by Duke Energy Renewables. Two of the third-party projects selected include battery storage. See the annual CPRE Program Plan included as Attachment II for additional details.

CPRE tranche 2 requested bids for 600 MW in DEC and 80 MW in DEP. The bid window closed March 9, 2020. Initial statistics showed DEC received 37 bids for approximately 1,850 MW. Twenty of the bids, representing approximately 1,050 MW were located within NC and the remaining 17 bids and 800 MW were located within SC. Three proposals were submitted with energy storage. Each of the 37 projects requested transmission interconnection.

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The finalists were selected from the initial bid list, and eleven projects were chosen for DEC with a combined capacity of 615 MW. Ten of the projects representing 540 MW are located in NC and one project at 75 MW is located in SC. There were no projects with energy storage selected.

All of the projects plan to employ a single axis tracking configuration. The weighted average price decrement for these proposals is approximately $4.90/MWh. No projects have executed contracts yet, and the contract negotiation window will close October 15, 2020.

The volume of any future tranches of CPRE will depend on the final results of tranche 2, as well as, the continued increases in capacity referred to in this document as the "Transition MW". These "Transition MW" represent the total capacity of renewable generation projects in the combined Duke Balancing Authority area that are (1) already connected; or (2) have entered into purchase power agreements (PPAs) and interconnection agreements (IAs) as of the end of the 45-month competitive procurement period, and which are not subject to curtailment or economic dispatch. The total CPRE target of 2,660 MW will vary based on the amount of Transition MW at the end of the 45-month period, which NC HB 589 expected to total 3,500 MW. If the aggregate capacity in the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount and vice versa. As of May 2020, there is approximately 4,020 MW of solar capacity and 280 MW of non-solar capacity that meet NC HB 589's definition of "Transition MW", meaning CPRE will be reduced by a minimum of 800 MW. The company believes the Transition may ultimately exceed 3,500 MW by as much as 1,850 MW, and possibly more depending on the extent to which SC Act 62 and Interconnection Queue reform drive new solar growth in SC by the end of the 45-month CPRE period.

NC AND SC INTERCONNECTION QUEUES

Through the end of 2019, DEC had more than 750 MW of utility scale solar on its system, with approximately 30 MW interconnecting in 2019. When renewable resources were evaluated for the 2020 IRP, DEC reported approximately 160 MW of third-party solar construction in progress and approximately 5,000 MW in the interconnection queue. Details of the number of pending projects and pending capacity by state are included in Appendix K.

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Projecting future solar connections from the interconnection queue presents a significant challenge due to the large number of project cancellations, ownership transfers, interconnection studies required, and the unknown outcome of which projects will be selected through the CPRE program. Additionally, any future efforts to reform the transmission or distribution interconnection queues could cause these projections to vary.

DEC's contribution to the Transition depends on many variables including connecting projects under construction, the expected number of renewable projects in the queue with a PPA and IA, SC Act 62, and SC DER Program Tier I. As of May 31, 2020, DEC had nearly 250 MW of solar capacity with a PPA and IA, and roughly 140 MW of non-solar renewable capacity with PPAs that extend through the 45-month CPRE period. A number of additional projects in the queue are expected to acquire both a PPA and IA prior to the expiration of the 45-month period defined in NC HB 589, potentially resulting in approximately an additional 300 MW contributing to the Transition. In total, DEC may contribute roughly one-quarter of the Transition MW with DEP accounting for the remaining three-quarters.

NC REPS COMPLIANCE

DEC remains committed to meeting the requirements of NC REPS, including the solar, poultry waste, and swine waste set-asides, and the general requirement, defined as the total REPS requirement net of the three set-asides, which will be met with additional renewable and energy efficiency resources. DEC's long-term general compliance needs are expected to be met through a combination of renewable resources, including RECs obtained through the NC HB 589 competitive procurement process. For details of DEC's NC REPS compliance plan, please reference the NC REPS Compliance Plan, included as Attachment I to this IRP.

NC HB-589 COMPETITIVE PROCUREMENT AND UTILITY-OWNED SOLAR

DEC continues to evaluate utility-owned solar additions to grow its renewables portfolio. For example, DEC owns and operates three utility-scale solar projects, totaling 76 MW-AC, as part of its efforts to encourage emission free generation resources and help meet its compliance targets:

- Monroe Solar Facility – 55 MW, located in Union County, North Carolina placed in service on March 29, 2017

- Mocksville Solar Facility – 15 MW, located in Davie County, North Carolina placed in service on December 16, 2016
- Woodleaf Solar Facility – 6 MW, located in Rowan County, North Carolina placed in service on December 21, 2018

No more than 30% of the CPRE Program requirement may be satisfied through projects in which Duke Energy or its affiliates have an ownership interest at the time of bidding. DEC and Duke Energy Renewables were each awarded approximately 20% of the capacity selected in the first tranche of CPRE. NC HB 589 does not stipulate a limit for DEC's option to acquire projects from third parties that are specifically proposed in the CPRE Request for Proposals (RFP) as acquisition projects, though any such project will not be procured unless determined to be among the most cost-effective projects submitted.

ADDITIONAL FACTORS IMPACTING FUTURE SOLAR GROWTH

According to BloombergNEF and the Solar Energy Industries Association (SEIA), the solar industry has not been immune to the impacts of COVID-19.[5] [6] The industry has experienced a significant loss in employment in the United States with most of the job losses and impacts associated with distributed generation. The pandemic has certainly introduced supply chain risks, and anecdotal evidence suggests that project financing is becoming more challenging, especially with the likely contraction of tax equity markets. Offsetting these concerns is a more diversified supply chain, especially in the United States, which helps to mitigate some of the supply chain risks. In addition, the U.S. Congress has passed several bills to help provide stimulus and liquidity in the markets, and there are various infrastructure legislative proposals that contain incentives to help the solar industry to continue to move forward. Taken together, the prevailing consensus seems to be that utility scale projects may be delayed, but it is unlikely that there will be large scale cancellations.

Beyond the immediate COVID-19 concerns, there are numerous other factors that impact the Company's forecast of future solar growth in the Carolinas. Key among these is potential changes in the Company's avoided cost in either NC or SC, as these may impact the development of projects under

[5] https://www.powerengineeringint.com/renewables/bnef-predicts-slow-down-in-clean-energy-economy-due-to-covid-19/.
[6] https://www.seia.org/sites/default/files/2020-05/SEIA-COVID-Impacts-National-Factsheet.pdf.

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PURPA, NC HB 589, and SC Act 62. Avoided cost forecasts are subject to variability due to changes in factors such as natural gas and coal commodity prices, system energy and demand requirements, the level and cost of generation ancillary service requirements, and interconnection costs. PURPA requires utilities to purchase power from QFs at or below the utility's avoided cost rates. NC HB 589 requires that competitive bids are priced below utility's avoided cost rates, as approved by the NCUC, in order to be selected. Given the potential for changes in the avoided cost rates, the installed cost of solar remains a critical input for forecasting how much solar will materialize in the future. This stems from the fact that the actual cost of solar is not related to the PURPA avoided cost rates, even though solar investment was possible in the past at those avoided cost rates.

Installed solar costs encompass many variables, including physical components such as PV modules, inverters, electrical, and structural equipment, as well as engineering design, O&M and interconnection charges, to name a few. Solar panel prices have been declining at a fairly significant rate during the past decade and are expected to continue this decline into the future, although the Section 201 tariffs that were enacted in 2018 will continue to impact module costs at least through 2021. The tariff is related to solar modules and cells and is set at 20% for the remainder of 2020 and dropping to 15% in 2021, which would be the last year the tariffs are in effect. Additional factors that could put upward pressure on solar costs include direct interconnection costs, as well as costs incurred to maintain the appropriate operational control of the facilities. Finally, as panel prices have decreased, there has been more interest in installing single-axis tracking (SAT) systems (as demonstrated in CPRE tranches 1 and 2) and/or systems with higher inverter load ratios (ILR) which change the hourly profile of solar output and increase expected capacity factors. DEC models fixed tilt and SAT system hourly profiles with a range of ILRs as high as 1.6 (DC/AC ratio).

In summary, there is a great deal of uncertainty in both the future avoided costs applied to solar and the expected price of solar installations in the years to come. As a result, the Company will continue to closely monitor and report on these changing factors in future IRP and competitive procurement filings.

NC HB 589 CUSTOMER PROGRAMS

In addition to the CPRE program, NC HB 589 offers direct renewable energy procurement for major military installations, public universities, and other large customers, as well as a community solar program. These programs are in addition to the existing SC Act 236 Programs and upcoming SC Act 62 programs.

As part of NC HB 589, the renewable energy procurement program enables large customers to procure renewable energy attributes from new renewable energy resources and receive a bill credit for the energy and capacity provided to DEC's system. The program allows for up to 600 MW of total capacity, with set asides for military installations (100 MW of the 600 MW) and the University of North Carolina (UNC) system (250 MW of the 600 MW). The 2020 IRP base case assumes all 600 MW of this program materialize, with the DEC/DEP split expected to be roughly 65/35. If all 600 MW are not utilized, the remainder will roll back to the competitive procurement, increasing its volume.

The community solar portion of NC HB 589 calls for up to 20 MW of shared solar in DEC. This program is similar to the SC Act 236 Shared Solar program in that it allows customers who cannot or do not want to put solar on their property to take advantage of the economic and environmental benefits of solar by subscribing to the output of a centralized facility. A key difference between the SC Act 236 Shared Solar program and the NC HB 589 Shared Solar program is that HB 589 does not allow the program to be subsidized. Customers must be credited at avoided cost and projects cannot be greater than 5MW. An RFP issued in 2019 with these parameters resulted in no bids. The 2020 IRP Base Cases assume that all 20 MW of the NC HB 589 shared solar program materializes starting in 2022.

NC HB 589 also established a rebate program for rooftop solar, limited to 10 MW of installed capacity per utility per year over 2018 through 2022. There are rules governing residential and non-residential customers, along with set asides for nonprofit organizations. Any set asides not used by year end 2022 will be reallocated for use by any customer type who meets the necessary qualifications. Since its inception in 2018, the rebate program has spurred greater interest in solar installations and therefore, more net metered customers in NC. Residential and non-residential capacity limits were quickly fully subscribed in 2018, 2019 and 2020. DEC NC installed approximately 13 MW of rooftop solar in 2018 and approximately 23 MW of rooftop solar in 2019. Through May of 2020, installed rooftop solar capacity is approximately 11 MW. For further discussion of rooftop solar projections, see below, as well as, Appendix C.

SC ACT 236 AND SC ACT 62

Steady progress continues to be made with the first two tiers of the SC DER Program summarized below, completion of which would enable DEC to invest in the third tier:

- **Tier I:** 40 MW of solar capacity from facilities each >1 MW and ≤ 10 MW in size connected to the distribution system.

- **Tier II:** 40 MW of behind-the-meter solar facilities for residential, commercial and industrial customers, each ≤1 MW, 25% of which must be ≤ 20 kilowatts (kW). Since Tier II is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load.

- **Tier III:** Investment by the utility in 40 MW of solar capacity from facilities each >1 MW and ≤10 MW in size connected to the distribution system. Upon completion of Tiers I and II (to occur no later than 2021), the Company may directly invest in additional solar generation to complete Tier III.

DEC has executed twelve PPAs totaling approximately 38 MW and is working to complete Tier I. Tier II incentives have resulted in growth in rooftop solar in DEC, which now has over 80 MW of rooftop solar installed. The 2% net metering application cap of 80 MW established in Act 236 was reached in DEC SC but has since been eliminated by SC Act 62.

The Company launched its first Shared Solar program in DEC as part of Tier I in the first quarter of 2019. Duke Energy designed its initial SC shared solar program to have strong appeal to residential and commercial customers who rent or lease their premises, residential customers who reside in multifamily housing units or shaded housing or for whom the relatively high up-front costs of solar PV make net metering unattainable, and non-profits who cannot monetize the ITC. To make the program financially feasible, subscription fees are subsidized by the ratebase. The program capacity is 3 MW including 400 kW set aside for low to moderate income (LMI) customers earning less than 200% of the federal poverty level. The unreserved 2,600 kW of capacity sold out within 3 months due to the program's strong economic proposition. As of the end of June 2020, the low to moderate income carve-out is fully subscribed as well.

TABLE E-1

DEC SHARED SOLAR PROGRAM

	AVERAGE SUBSCRIPTION KW PER PARTICIPANT	CUSTOMERS	CAPACITY (KW)
Residential LMI	2	200	400
Residential Non-LMI	5.01	271	2600
Non-Residential	124.3	10	

SC Act 62 passed in South Carolina on May 16, 2019. SC Act 62 will likely drive additional PURPA solar as DEC must offer fixed price PPAs to certain small power producers at avoided cost for a minimum contract term of 10 years. The 10-year rate is applicable for projects located in SC until DEC has executed IAs and PPAs with aggregated nameplate capacity equal to 20 percent of the previous 5-year average of DEC's SC retail peak load, or roughly 800 MW. After 800 MW have executed IAs and PPAs the Commission will determine conditions, rates, and terms of length for future contracts. Given there is roughly 2,700 MW of solar pending in DEC SC, the Company expects to meet 800 MW within the IRP planning period. The Company intends to closely monitor the capacity with executed IAs and PPAs, evaluate impacts on the NC HB 589 Transition MW and corresponding reduction in CPRE volume. Once the 800 MW threshold is reached, the SC PSC will determine the term limit for PURPA contracts in its sole discretion.

SC Act 62 also called for additional customer programs, requiring the utilities to file voluntary renewable energy programs within 120 days of SC Act 62 passing, and encouraging additional community solar. The Company has a proposed voluntary renewable energy program pending before the Commission, which would create a 150 MW program for DEC and DEP SC combined (113 MW in DEC) offering up to 20-year PPAs. The Companies are considering whether additional community solar should be pursued.

Finally, SC Act 62 lifted the cap on net metering, requiring the Company to offer full retail rate net metering through June 1, 2021, as approved through proceedings under Act 236. As required by the legislation, the Public Service Commission of South Carolina opened a docket in May 2019 to establish a solar choice metering tariff to go into effect for customer applications received after May 31, 2021 which would replace the meting tariff for new installations.[7] The Company expects net metering adoption to pick up to comparable levels of adoption observed in DEC-SC in 2017/2018 through June 2021. Future adoption after that date will be determined based upon the solar choice tariff terms approved by the SC PSC.

WIND

DEC considers wind a potential energy resource in the short and long term to support increased renewable portfolio diversity, an important resource for achieving the Company's 2050 net-zero carbon emission goal, as well as long-term general compliance need. However, sourcing wind remains challenging, whether the wind is imported from other states, sited within the Carolinas, or sited offshore.

In 2020, offshore wind energy is becoming a more viable alternative, but only one project near the Carolinas, the Avangrid Kitty Hawk project off the coast of North Carolina, has the necessary Bureau of Ocean Energy Management ("BOEM") offshore lease to begin construction. Several call areas began the process of evaluation along the North and South Carolina border but stalled out in recent years as BOEM refocused their efforts to areas with higher demand. These call areas could eventually become new leasing areas, but first BOEM's Task Force will need a representative from South Carolina to restart the permitting and approvals process.

The Company continues to evaluate options for increasing access to offshore wind energy into the Carolinas, however the cost to transport wind energy from the coast to the load centers located in central North Carolina and South Carolina is significant. In 2012, the North Carolina Transmission Planning Collaborative ("NCTPC") released a study that estimated transmission upgrade costs for moving wind into the Carolinas in a few different scenarios: the costs ranged from approximately $930M to $1,730M. While the Company continues working with the NCTPC to update estimates for integrating offshore wind into the DEP and DEC territories, the Company expects those costs to increase significantly as the costs to site and build new transmission infrastructure has increased over

[7] PSCSC Docket 2019-182E.

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the last decade. For further discussion of the transmission costs associated with moving offshore wind from the coast to load centers in the Carolinas, see Chapter 7.

Wind energy generated onshore in the Carolinas presents other challenges. The wind capacity (speeds and duration) are generally best in the mountains and along the coast of the Carolinas, but these locations also have hurdles. While the moratorium on building land-based wind in NC has recently expired, the Mountain Ridge Protection Act prevents building wind on ridgetops, and coastal tourism often deters siting on land along the coast. Aside from the policy barriers, there is a significant need for meteorological towers to collect wind speed history in key areas across the Carolinas to gain confidence in predicted capacity factors. The Carolinas onshore wind profiles used in this IRP were provided by a third party and may not be based on wind speeds measured near the expected hub heights.

While the Company is working to improve the quality of Carolinas onshore wind profiles for use in future IRPs it is expected that wind generation located in the central portion of the Carolinas would generally have much lower output than sites located on the coast or mountains, but the benefit of these sites would likely be lower transmission costs. These lower costs could potentially outweigh effects of lower output, particularly since their wind profiles are generally complementary to solar generation.

On-shore wind located outside of the Carolinas presents both economic and logistical challenges associated with constructing significant transmission infrastructure. In August 2017, DEC issued an RFP for delivered energy, capacity, and associated RECs from wind projects up to 500 MW. While bids received were not economically valuable enough to pursue, the Company has continued to evaluate potential projects. Out-of-state transmission costs and availability are one of the complicating factors for importing wind from out of state.

While wind energy continues to face challenges, the Company believes wind energy can become a viable resource by the end of the planning horizon. For this reason, Central Carolinas wind was included as an available resource in the base case, and the high renewable case includes both offshore and central US located wind as resources in the 2030 to 2035 timeframe. Additionally, the Company included higher levels of offshore wind in the 70% CO_2 Reduction: High Wind portfolio to demonstrate how diversifying the Company's resource mix can help achieve aggressive carbon emission reduction goals. The No New Gas Generatio portfolio also included offshore wind but the majority was serving DEP demand. It is possible that future policy may provide for cost and benefit sharing of emerging

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carbon free resources, such as offshore wind, across all customers in both utilities in order to equitably advance such technologies. For a more detailed summary of these portfolios, see Chapter 12 and Appendix A.

SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS

BASE WITH CARBON POLICY

The 2020 IRP Base with Carbon Policy case incorporates the projected and economically selected renewable capacities shown below. This case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond NC HB 589, including expected growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. The Base Case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

However, it is the Company's belief that continued declines in the installation cost of solar and storage will enable solar and coupled "solar plus storage" systems to contribute to energy and/or capacity needs. Additionally, the inclusion of a CO_2 emissions tax, or some other carbon emissions reduction policy, would further incentivize expansion of solar resources in the Carolinas. In the 2020 IRP, the capacity expansion model selected additional solar averaging approximately 100 MW per year beginning in 2025 and solar coupled with storage averaging approximately 120 MW annually beginning in 2028 if a CO_2 tax were implemented in the 2025 timeframe.

Unlike the first tranche of CPRE, the second tranche of CPRE did not yield any solar plus storage projects. The Company continues to believe that the combination of falling storage costs in addition to the most recent avoided cost rate structures proposed in both NC and SC provide strong price incentives for QFs to shift energy from lower priced energy-only hours to hours that have higher energy and capacity prices. This rate design provides incentives to encourage storage additions to solar projects. The Company this year is also projecting that a significant amount of incremental solar beyond NC HB 589 will be coupled with storage. The 2020 base case assumes storage is DC coupled with solar, has a four-hour duration, and the capacity of the battery storage is 25% of the capacity of the solar. In total, DEC expects approximately 1,525 MW of solar coupled with approximately 380 MW of storage by the end of 2035.

Additionally, Phase 1 of NREL's Integration of Carbon Free Resources Study, highlighted the benefit storage provides by reducing the curtailment of solar resources as significant levels of solar are added to the DEC system and create more excess energy conditions. At current levels of solar investment in DEC, curtailment is not a significant concern in the short-term due to the availability of pumped hydro storage resources. However, curtailment may become more prevalent towards the end of the planning horizon as solar investment is expected to expand in DEC.

Finally, as solar generation is expected to continue its expansion in DEC, interconnecting several thousand MW of new solar generation will likely require new transmission projects and could create logistical constraints due to limited transmission outage windows as these projects are implemented. For the last five years, DEC and DEP have interconnected approximately 500 MW of solar combined annually. While interconnections may potentially exceed those levels in the short-term, over the planning horizon, for base case planning purposes, the Company assumed interconnections were limited to 500 MW on an annual average basis. Since the majority of growth is expected in DEC, the DEC specific interconnection constraint was assumed to be 300 MW annually. The Company will continue to monitor interconnections, and should new, larger projects request interconnection to the DEC system or other efficiencies be realized, the level of interconnections may increase.

The Company anticipates a diverse renewable portfolio including solar, biomass, hydro, storage fed by solar, wind, and other resources. Actual results could vary substantially for the reasons discussed previously, as well as, other potential changes to legislative requirements, tax policies, technology costs, carbon prices, ancillary costs, interconnection costs, and other market forces. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table E-2 below.

TABLE E-2

DEC BASE WITH CARBON POLICY TOTAL RENEWABLES

DEC BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL
2021	966	0	132	0	1,099	387	0	132	0	519	10	0	132	0	142
2022	1,327	115	118	0	1,560	514	70	118	0	702	13	29	118	0	160
2023	1,673	134	81	0	1,888	636	81	81	0	797	17	34	81	0	131
2024	1,976	163	81	0	2,219	741	99	81	0	921	20	41	81	0	141
2025	2,268	192	59	0	2,519	844	116	59	0	1,019	23	48	59	0	129
2026	2,519	211	49	0	2,778	930	127	49	0	1,106	25	53	49	0	127
2027	2,708	335	49	0	3,091	977	202	49	0	1,228	27	84	49	0	160
2028	2,895	458	42	0	3,395	1,024	274	42	0	1,340	29	114	42	0	185
2029	3,082	656	42	0	3,779	1,071	390	42	0	1,502	31	164	42	0	236
2030	3,217	802	38	0	4,058	1,104	475	38	0	1,618	32	201	38	0	271
2031	3,352	948	30	0	4,330	1,138	559	30	0	1,727	34	237	30	0	301
2032	3,486	1,094	12	0	4,592	1,171	642	12	0	1,826	35	273	12	0	321
2033	3,620	1,238	3	0	4,861	1,205	724	3	0	1,932	36	310	3	0	349
2034	3,753	1,382	0	0	5,135	1,230	803	0	0	2,032	37	345	0	0	383
2035	3,885	1,525	0	150	5,560	1,242	875	0	11	2,127	38	381	0	50	469

Data presented on a year beginning basis.
Solar includes 0.5% per year degradation.
Capacity listed excludes REC Only Contracts.
Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study.

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While solar is not at its maximum output at the time of DEC's expected peak load in the summer, solar's contribution to summer peak load is large enough that it will likely push the time of summer peak to a later hour if solar generation levels continue to increase. However, solar is unlikely to have a similar impact on the morning winter peak due to little solar output in the morning hours. Solar capacity contribution percentages to summer and winter peak demands are assumed to be the same as those used in the 2019 IRP. Note, however the solar contribution to peak values now also include additional contributions provided by storage coupled with solar, assumed to be 100% of the storage capacity installed based on the results of the Capacity Value of Battery Storage study discussed in Appendix H and filed as Attachment IV to this IRP.

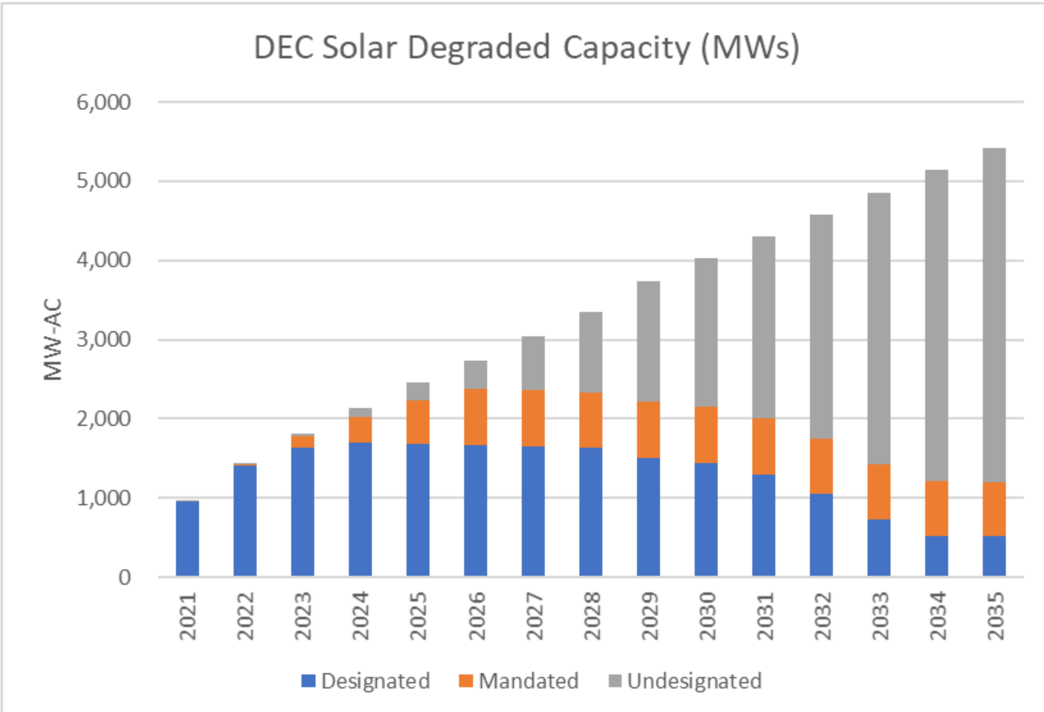
As a number of solar contracts are expected to expire over the IRP planning period, the Company is additionally breaking down its solar forecast into three buckets described below:

- **Designated**: Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.
- **Mandated**: Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236)
- **Undesignated**: Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing facilities or new facilities that enter into contracts that have not yet been executed.

Figure E-1 below shows DEC's breakdown of these three buckets through the planning period. Note for avoided cost purposes, the Company only includes the Designated and Mandated buckets in the base case. For determining the cost cap pricing in the second tranche of CPRE, the Company includes the Designated bucket only.

FIGURE E-1

DEC SOLAR DEGRADED CAPACITY (MW)



HIGH & LOW RENEWABLE CASES

Given the significant volume and uncertainty around solar investment, high and low solar portfolios were compared to the Base Case described above. The portfolios do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. Additionally, the high case also considers a combination of onshore and offshore wind as viable resources beginning in the 2030 timeframe. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed. Tables E-3 and E-4 below provide the high and

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low solar nameplate capacity summaries, as well as, their corresponding expected contributions to summer and winter peaks. For more details on these sensitivities see Appendix A.

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TABLE E-3

DEC HIGH RENEWABLES SENSITIVITY

DEC HIGH RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	966	0	132	0	1,099	387	0	132	0	519	10	0	132	0	142
2022	1,327	115	118	0	1,560	514	70	118	0	702	13	29	118	0	160
2023	1,673	134	81	0	1,888	636	81	81	0	797	17	34	81	0	131
2024	1,976	163	81	0	2,219	741	99	81	0	921	20	41	81	0	141
2025	2,193	192	59	0	2,444	818	116	59	0	993	22	48	59	0	129
2026	2,369	211	49	0	2,629	879	128	49	0	1,056	24	53	49	0	125
2027	2,737	342	49	0	3,127	984	206	49	0	1,239	27	85	49	0	162
2028	3,103	474	42	0	3,619	1,076	281	42	0	1,398	31	118	42	0	191
2029	3,479	613	42	0	4,134	1,170	358	42	0	1,569	35	153	42	0	230
2030	3,699	750	38	0	4,488	1,225	435	38	0	1,698	37	188	38	0	263
2031	3,925	893	30	90	4,938	1,245	506	30	28	1,810	38	223	30	54	346
2032	4,158	1,117	12	180	5,468	1,266	621	12	57	1,956	39	279	12	109	440
2033	4,406	1,352	3	270	6,031	1,289	736	3	85	2,112	41	338	3	163	545
2034	4,668	1,600	0	360	6,628	1,312	854	0	113	2,279	42	400	0	217	659
2035	4,940	1,856	0	625	7,421	1,337	972	0	160	2,469	43	464	0	336	844

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TABLE E-4

DEC LOW RENEWABLES SENSITIVITY

DEC LOW RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	966	0	132	0	1,099	387	0	132	0	519	10	0	132	0	142
2022	1,327	115	118	0	1,560	514	70	118	0	702	13	29	118	0	160
2023	1,673	134	81	0	1,888	636	81	81	0	797	17	34	81	0	131
2024	1,976	163	81	0	2,219	741	99	81	0	921	20	41	81	0	141
2025	2,193	192	59	0	2,444	818	116	59	0	993	22	48	59	0	129
2026	2,369	211	49	0	2,629	879	128	49	0	1,056	24	53	49	0	125
2027	2,584	210	49	0	2,842	946	126	49	0	1,121	26	52	49	0	127
2028	2,797	208	42	0	3,047	999	124	42	0	1,165	28	52	42	0	122
2029	3,009	207	42	0	3,258	1,052	122	42	0	1,216	30	52	42	0	124
2030	3,145	281	38	0	3,465	1,086	166	38	0	1,290	31	70	38	0	140
2031	3,280	355	30	0	3,665	1,120	208	30	0	1,358	33	89	30	0	151
2032	3,414	428	12	0	3,855	1,154	251	12	0	1,417	34	107	12	0	154
2033	3,548	501	3	0	4,052	1,187	292	3	0	1,483	35	125	3	0	164
2034	3,682	574	0	0	4,255	1,220	334	0	0	1,554	37	143	0	0	180
2035	3,815	646	0	0	4,460	1,235	371	0	0	1,607	38	161	0	0	199

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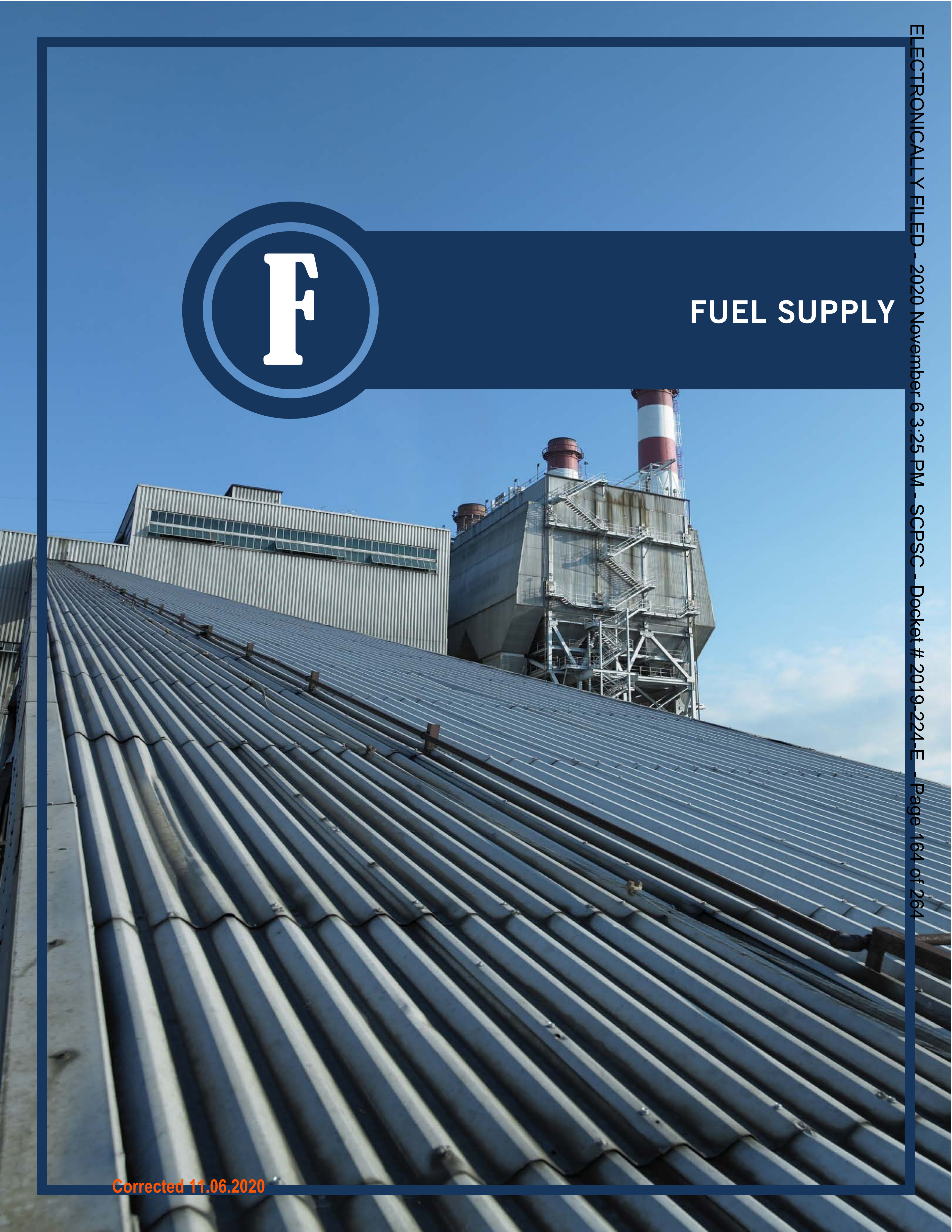

F

FUEL SUPPLY

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APPENDIX F: FUEL SUPPLY

Duke Energy Carolinas' current fuel usage consists of a mix of coal, natural gas and uranium. Oil is used for peaking generation and natural gas continues to play an increasing role in the fuel mix due to lower pricing and the addition of a significant amount of combined cycle generation and dual fuel capability at three coal facilities. A brief overview and issues pertaining to each fuel type are discussed below.

NATURAL GAS

During 2019 NYMEX Henry Hub natural gas prices averaged approximately $2.51 per million BTU (MMBtu) and U.S. lower-48 net dry production averaged approximately 92 billion cubic feet per day (BCF/day). Natural gas spot prices at the Henry Hub averaged approximately $2.00 per MMBtu in January 2020, while spot pricing decreased throughout the remaining winter months and averaged $1.75 per MMBtu at the end of March 2020. The lower short-term spot prices in February and March 2020 were driven by both fundamental supply and demand factors as winter temperatures remained mild.

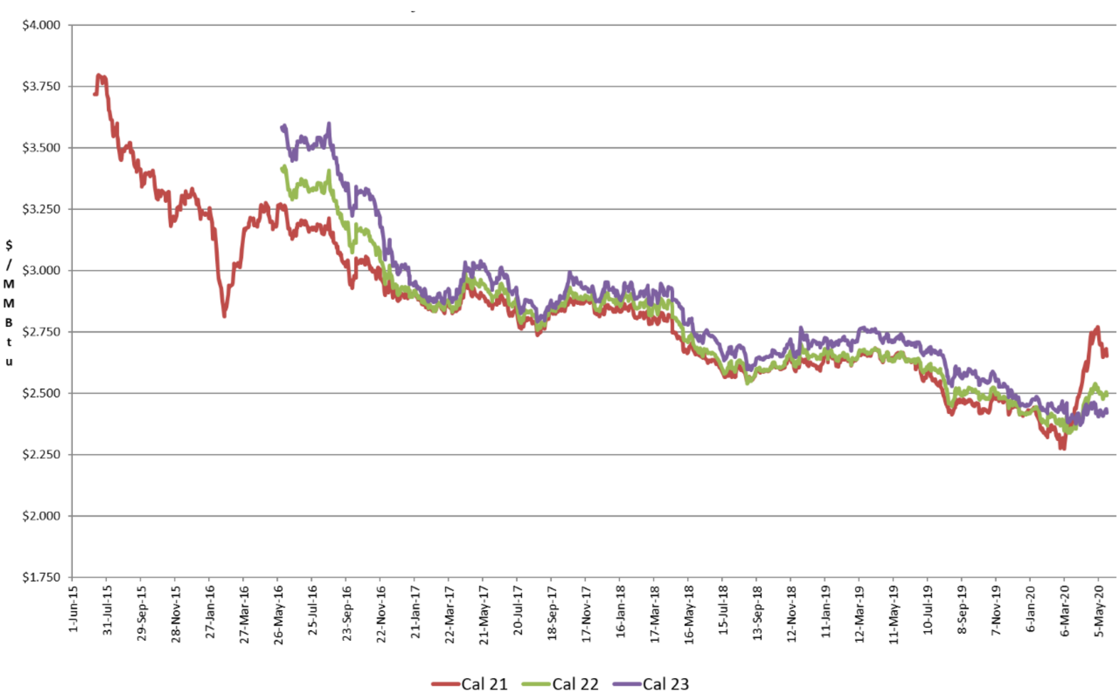
Average daily U.S. net dry production levels of approximately 92 BCF/day in the first quarter of 2020 were 4.2 BCF/day higher than the comparable period in 2019. The EIA is forecasting a decrease this year from a reported 93.1 BCF/day in April, to 85.4 BCF/day by December. Most of this decline in production will be seen in the Appalachian region. Prices are discouraging producers from engaging in natural gas-directed drilling, and in the Permian region, where low oil prices reduce associated gas output from oil-directed wells. Current forecasts show dry natural gas production averaging 84.9 BCF/day in 2021, rising in the second half of the year in response to higher prices.

Following this year's winter withdrawal season, U.S. working gas in storage levels were reported to be at approximately 2.3 trillion cubic feet (TCF) as of April 30, 2020, coming in 20% above the 5-year average between 2015-2019. Lower-48 U.S. overall demand in the first quarter of 2020 was lower than normal due to the above average temperatures throughout the winter months.

While Henry Hub spot prices averaged $1.63 per MMBtu during the first week of June 2020, the EIA forecasts natural gas prices will generally rise through 2020 as a decline in U.S. production is seen. Spot prices at Henry Hub are being forecasted by the EIA to average $2.14 per MMBtu this year, and then increasing to an annual average of $2.89 in 2021 as a result of lower natural gas production.

The EIA is expecting domestic natural gas consumption to see a 3.4 BCF/day decline compared to 2019. Overall U.S. forecasts for the year are down mainly due to reduced economic activity related to COVID-19, led by a decrease in demand during the first quarter as a result of milder-than-normal temperatures. Per the EIA's short-term energy outlook (STEO) released on May 26, 2020, natural gas consumption in the residential and commercial sectors is forecasted to decrease by 3.7% and 6.9%, respectively. Although those two sectors account for a small fraction of U.S. natural gas consumption outside of winter months when heating demand is high, the EIA expects weaker economic conditions in the coming months to further reduce average consumption in the commercial sector. With the weak economic conditions, the EIA also expects industrial natural gas demand to decline in the U.S. from an average of 21.4 BCF/day in 2019, to an average of 19.9 BCF/day in 2020, which will be at its lowest point since the summer of 2016. Following the first half of 2020 short-term energy outlook, which expected natural gas used for electric power to grow 1.6 BCF/day compared to the first half of 2019 as a result of low natural gas prices, and lower-than-expected natural gas capacity additions, the EIA forecasts to see a decline during the second half of 2020. With natural gas prices forecasted to rise during that time, the STEO shows a reduction of natural gas consumption for electric power by 2.2BCF/day compared to the second half of 2019. The EIA's most recent short-term energy outlook also reports an expected rise in the May Henry Hub spot price from $1.88/MMBtu to $2.94/MMBtu by December 2020. These higher natural gas prices will result in some coal-fired generation units to become more economical to dispatch versus natural gas-fired units. EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants to rise from 37% in 2019 to 39% in 2020. As a result, coal's forecast share of electricity generation falls from 24% in 2019 to 19% in 2020. According to Baker Hughes, as of June 5, 2020, the U.S. rig count was at 284. This is 691 less than this time last year.

FIGURE F-1
HENRY HUB NATURAL GAS PRICE FORWARD CURVE



Looking forward, the forward 5 and 10-year observable market curves are at $2.39 and $2.53 per MMBtu, respectively, as of the June 5, 2020 close. In addition, as of the close of business on June 5, 2020, the one (1), three (3) and five (5) years strips averaged approximately $2.48 per MMBtu. As illustrated with these price levels and relationships, the forward NYMEX Henry Hub price curve is relatively flat with the periods of 2022 and 2023 currently trading at discounts to 2021 prices. The gas market is expected to remain relatively stable due to the recent balancing act of lower production to account for the lack of demand during the COVID-19 pandemic. The North American gas resource picture is a story of unconventional gas production dominating the gas industry. Shale gas now accounts for approximately 97% of net natural gas production today. As noted earlier, per the EIA's short-term outlook dated May 12, 2020, the EIA expects dry gas production to average 89.8 BCF/day by the end of 2020 and fall by 5 BCF/day in 2021 to 84.9 BCF/day. The United States is a net exporter of natural gas, with net exports expected to average 7.3 BCF/day in 2020. According to the EIA forecast, US LNG is forecasted to be 8.9 BCF/day by the end of 2021.

The US power sector still represents the largest area of potential new gas demand, but increased usage is expected to be somewhat volatile as generation dispatch is sensitive to commodity price relationships and growth in renewable generation. Looking forward, economic dispatch competition is expected to continue between gas and coal, although forward natural gas prices have continued to decline and there has been permanent loss in overall coal generation due to the number of coal unit retirements.

In order to ensure adequate natural gas supplies, transportation and storage, the company has gas procurement strategies that include periodic RFPs, market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply and transportation portfolio that supports DEC's generation facilities. With respect to storage and transportation needs, the company continues to add incremental firm pipeline capacity and gas storage as the gas generation fleet has grown. The company will continue to evaluate competitive options to meet its growing need for gas pipeline infrastructure as the gas generation fleet grows.

The Atlantic Coast Pipeline (ACP) project was an approximately 600-mile greenfield natural gas pipeline project originating in West Virginia with ultimate delivery into Piedmont's system in Robeson County, North Carolina providing pipeline diversity for the state of NC as well as pipeline diversity for the DEP and DEC electric systems. ACP had an initial capacity of 1.5 BCF/day and would have provided direct upstream access to natural gas production in the Marcellus and Utica shale basins of West Virginia, Pennsylvania and Ohio. On July 5th, 2020 Dominion Energy and Duke Energy announced the cancellation of ACP due to on-going legal uncertainty, anticipated delays and increasing cost uncertainty. DEP and DEC still need additional upstream firm interstate transportation service to support existing and future gas generation in the Carolinas despite the cancellation of the project. Given this change in planned interstate natural gas transportation infrastructure coming into the eastern part of NC, the 2020 IRP no longer includes direct access to interstate Marcellus and Utica shale basins coming into the eastern portions of NC.

To reliably and cost effectively support both the existing natural gas generation fleet and future combined cycle natural gas generation growth the 2020 IRP assumes incremental firm transportation service is obtained, as contemplated in the ACP project, with the exception of coming from alternate pipeline providers. While such incremental firm transportation service may not produce the additional geographic pipeline transportation diversity of the original ACP project it will look to provide needed supply diversity, improve supply reliability and provide greater price stability for customers by reducing reliance on increasingly constrained delivered Transco Zone 5 natural gas supply. In this IRP, firm interstate transportation service is assumed to be procured for any new combined cycle natural gas resource selected in the generation portfolios in this plan along with estimates of the cost of this firm transportation service. The estimated firm transportation service costs were considered in the resource selection process and are included in the financial results presented.

Consistent with past IRPs, the planning process does not assume incremental interstate capacity is procured for additional simple cycle CTs given their low capacity factors. Rather, CTs are assumed to be constructed as dual fuel units that are ultimately connected to Transco Zone 5. Simple cycle CTs will rely on delivered Zone 5 gas supply or, if needed, ultra-low sulfur fuel oil during winter periods where natural gas has limited availability, the pipeline has additional constraints, or if gas is higher priced than the cost to operate on fuel oil. Coal units with gas dual fuel functionality were also not assumed to have firm interstate transportation service. This assumption may be required to change if coal functionality was to be removed from any unit and the unit was solely gas dependent. The Company will continue to refine transportation volume and cost assumptions over time as future developments in interstate delivery options in the Carolinas are more fully known.

COAL

The main determinants for power sector coal demand are electricity demand growth and non-coal electric generation, namely nuclear, gas, hydro and renewables. With electricity demand growth remaining very low, continued steady nuclear and hydro generation, and increasing gas-fired and renewable generation, coal-fired generation continues to be the marginal fuel experiencing declines. According to the EIA, electric power sector demand has been steadily dropping and accounted for 539 million tons (90%) of total demand for coal in 2019. Additionally, projections show continued strong supply and fluctuating prices for natural gas which, when combined with the addition of new gas-fired combined cycle generating capacity and new projects to enable gas to be co-fired at coal burning stations, continues to result in more volatile coal burns.

Coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency (EPA) regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

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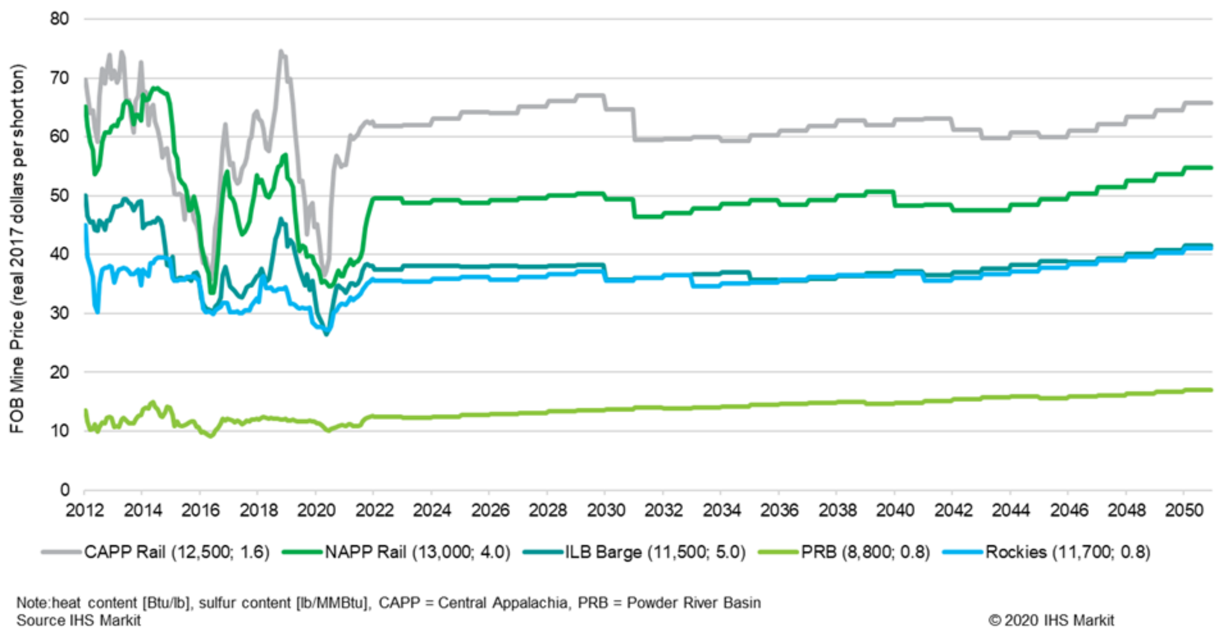
According to IHS Markit, future coal prices for the CAPP, NAPP, ILB and PRB coals are expected to be in a steady downward trend through 2020 when they see a modest rebound, flatten and begin to modestly and steadily rise. Future pricing for Rockies coal is expected to steadily rise for the next 20-years.

FIGURE F-2
MINEMOUTH COAL PRICE FORWARD CURVE



With the issuance of the Affordable Clean Energy (ACE) rule in 2019, the fundamental industry outlook now anticipates that less efficient higher cost coal unit retirements will accelerate, with only the lowest-cost production surviving long term. IHS Markit expects 80 GW of coal plant retirements from 2020 to 2025, followed by 42 GW from 2026 to 2030, and 68 GW from 2031 to 2050.

Coal exports have not been immune to global market pressures as total coal exports declined 20% in 2019 from historically high levels in 2018. IHS Markit expects US exports to be curtailed in the short term due to the economic impacts of COVID-19, but projects that exports, especially for metallurgical coal, should stabilize over the long-term horizon. Lower cost thermal export demand is projected to be

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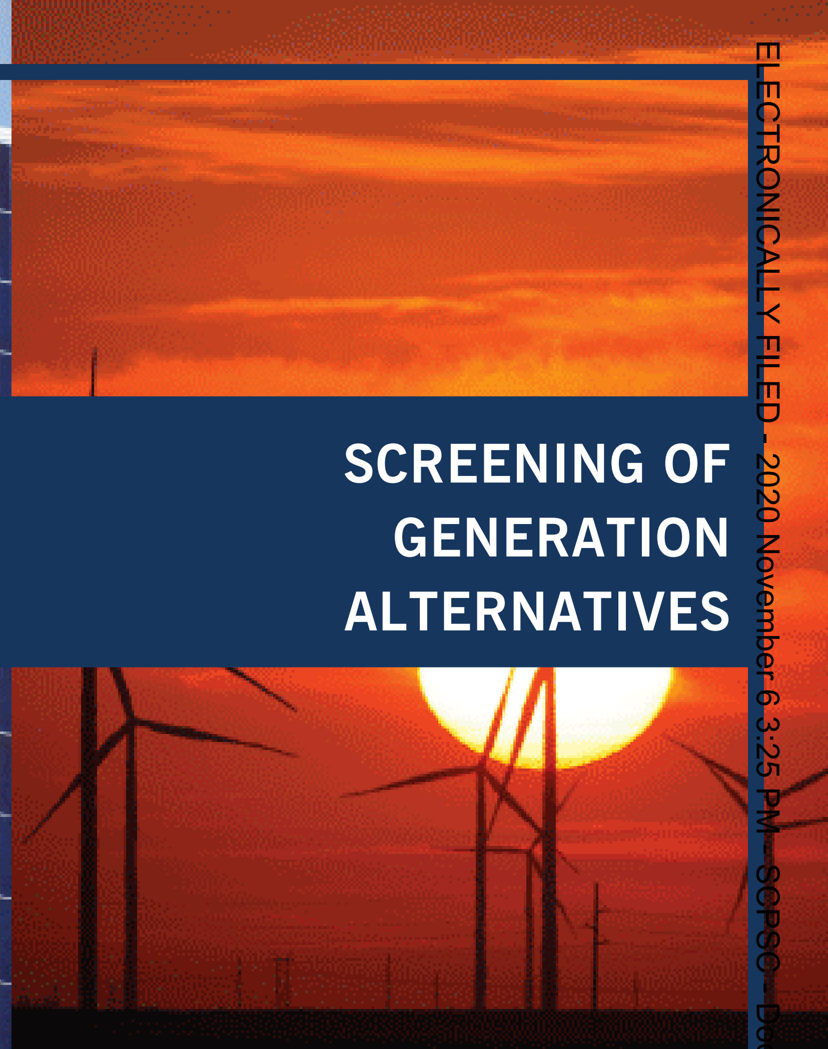
mostly limited to NAPP and ILB longwall operations, while higher cost production mines are expected to struggle during weaker market years.

The Company continues to maintain a comprehensive coal procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts.

NUCLEAR FUEL

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, DEC staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases.

Due to the technical complexities of changing suppliers of fuel fabrication services, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts. As fuel with a low-cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear generation costs are expected to be competitive with alternate generation and customers will continue to benefit from the Company's diverse generation mix.



G

SCREENING OF GENERATION ALTERNATIVES

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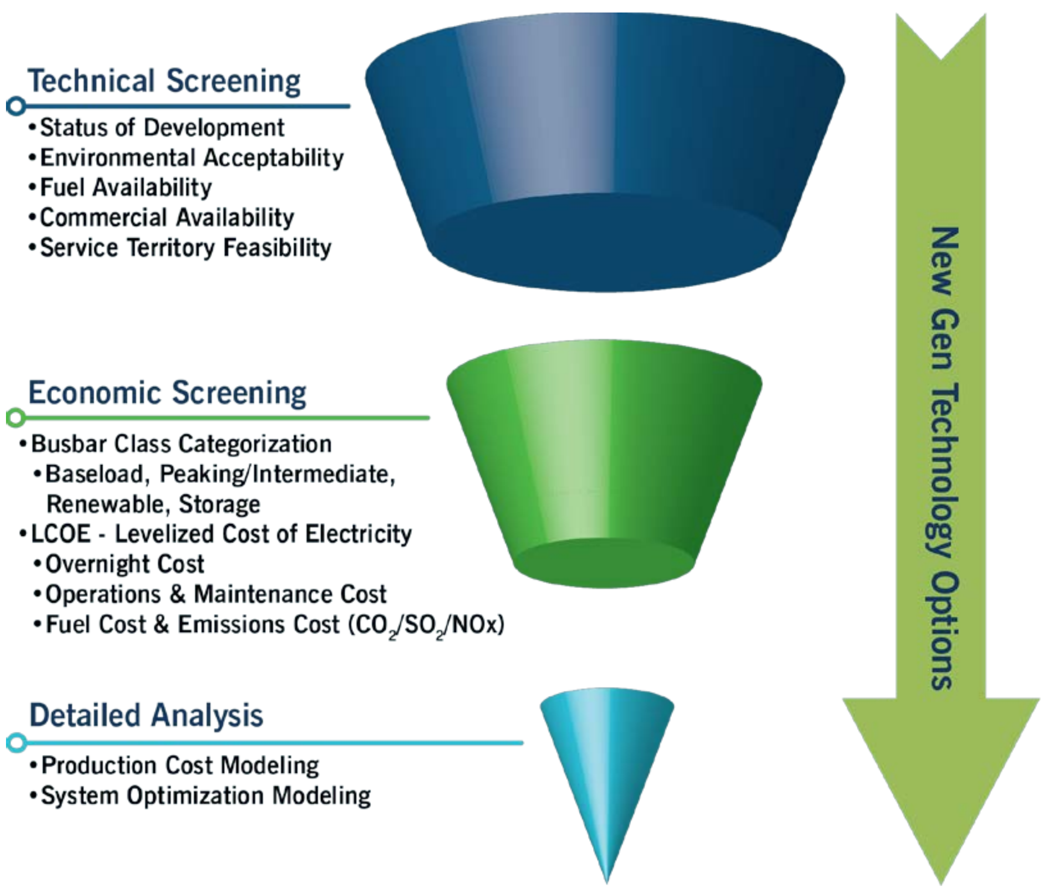
APPENDIX G: SCREENING OF GENERATION ALTERNATIVES

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective as well as an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues, and feasibility in the Duke Energy service territory.

Economic screening is performed using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process.

FIGURE G-1
NEW GENERATION TECHNOLOGIES SCREENING PROCESS



TECHNICAL SCREENING

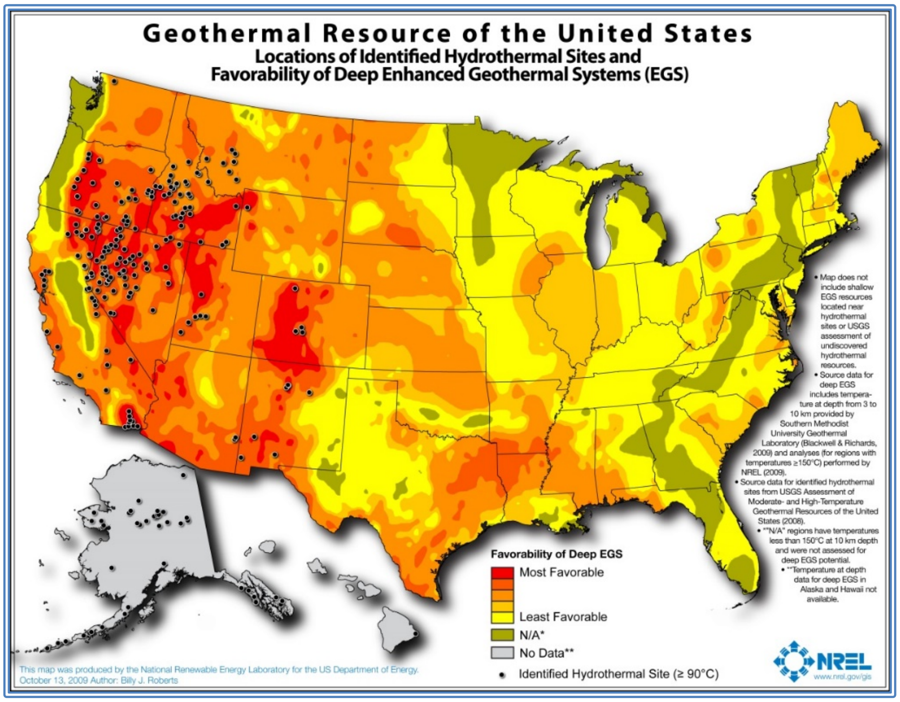
The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially viable/available for utility-scale application. However, fuel cells have the potential to provide carbon-free energy if they utilize hydrogen as a fuel source and therefore continue to be reviewed to determine their applicability for future carbon reductions.

Geothermal was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project – see Figure G-2, below. However, advanced geothermal is under development and is performing demonstration projects. Recent developments in deep direct-use geothermal may expand geothermal's applicability into some of the least favorable geological formations as seen in Figure G-2. Although these technologies have not yet reached commercial status, Duke Energy will continue to follow the technology as it may present geothermal energy capability within its service territory in the future.

FIGURE G-2

NREL GEOTHERMAL RESOURCE MAP OF THE U.S.



Small Modular Nuclear Reactors (SMR) are generally defined as having a power output of less than 300 MW per reactor and utilizing water as the coolant. They typically have the capability of grouping a number of reactors in the same location to achieve the desired power generating capacity for a plant. In 2012, the U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." SMRs continue to gain interest as they contribute no emissions to the atmosphere and, unlike their predecessors, provide flexible operating capabilities alongside inherently safer designs.

NuScale Power is the leader in SMR design and licensing in the US. A NuScale power module is expected to output 60 MW each, and a standard plant offering is expected to contain 12 modules. The NuScale design is expected to receive a certification from the Nuclear Regulatory Committee (NRC) in 2021, which would allow utilities to pursue the design as a new commercial asset. The first NuScale module is expected to reach commercial status in the late 2020s timeframe.

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Two additional SMR designs are under development domestically including the GE Hitachi BWRX-300 and the Holtec SMR-160. The BWRX-300 design utilizes design features from the NRC-certified ESBWR, so although GE began their licensing process with the NRC after NuScale, they are expected to reach commercial availability in a similar timeframe. Holtec has not yet submitted a formal design certification request to the NRC and therefore there is no estimated commercialization timeframe in the US.

Similar to 2018, while SMRs were "screened out" in the Technical Screening phase of the technology evaluations due to commercial availability, they were allowed to be selected as a resource in the System Optimizer (SO) model in order to allow the model to meet the high CO_2 emission constraints in the sensitivity analysis. As a result, SMRs have been depicted on the busbar screening curves as an informative item. Duke Energy will be monitoring the progress of the SMR projects for potential consideration and evaluation for future resource plans as they provide an emission-free, diverse, flexible source of generation.

Advanced Nuclear Reactors are typically defined as nuclear power reactors employing fuel and/or coolant significantly different from that of current light water reactors (LWRs) and offering advantages related to safety, cost, proliferation resistance, waste management and/or fuel utilization. These reactors are characteristically typed by coolant with the main groups including liquid-metal cooled, gas cooled, and molten-salt fueled/cooled. There are at least 25 domestic companies working on one or multiple advanced reactor designs funded primarily by venture capital investment, and even more designs are being considered at universities and national labs across the country. There is also significant interest internationally with at least as many international companies pursuing their own advanced reactor designs in several countries across the world.

Specifics of the reactor vary significantly by both coolant type and individual designs. The reactors are projected to range in size from the single MW scale to over 1000 MW, with the majority of the designs proposing a modular approach that can scale capacity based on demand. Designs are typically exploring a flexible deployment approach which could scale power outputs to align with renewable/variable outputs. The first commercially available advanced reactors are targeting the late 2020s for deployment, although most designs are projected to be available in the 2030s. Significant legislative efforts are currently being made to further the development of advanced reactors in both the house and senate at the national level, and new bills continue to be introduced.

Duke Energy has been part of an overall industry effort to further the development of advanced reactors since joining the Nuclear Energy Institute Advanced Reactor Working Group at its formation in early 2015. Additionally, Duke Energy participates on three Advanced Reactor companies' industry boards and has hosted several reactor developers for early design discussions. Duke Energy has also participated in other industry efforts such as EPRI's Owner-Operator Requirements Document, which outlines requirements and recommendations for Advanced Reactor designs. Duke Energy will continue to allot resources to follow the progress of the advanced reactor community and will provide input to the proper internal constituents as additional information becomes available.

Poultry waste and swine waste digesters remain relatively expensive and are often faced with operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies. See Appendix E for more information regarding current and planned Duke Energy poultry and swine waste projects.

Solar Steam Augmentation systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. As the price of solar panels continues to drop, solar steam augmentation's economics compared to photovoltaic solar likely prevent this technology from moving forward. However, Duke Energy will continue to monitor developments in the area of steam augmentation.

Supercritical CO_2 Brayton Cycle is of increasing interest; however, the technology is still in the demonstration process. NET Power is the leading developer of the technology and is working on a pilot project. The early issues with the pilot show that the technology has not yet reached commercial status. Duke Energy will continue to monitor pilot and early commercial Supercritical CO_2 Brayton Cycle projects to determine if the technology passes the technical screening in future years.

Hydrogen as a fuel offers an advantage over traditional fossil fuels in not emitting carbon dioxide when burned. There has been substantial renewed interest by the industry in pursuing hydrogen as a replacement fuel for natural gas. Although promising, hydrogen as a utility fuel is still in the early stages from both a production and generation standpoint. Turbine manufacturers have proven successful with hydrogen/natural gas cofiring of up to 30% hydrogen by volume without significant gas turbine alterations in many of the combined cycle and combustion turbine plants currently in operation, dependent on gas turbine type. However, to move to 100% hydrogen-fueled turbines substantial improvements in turbine technology are required. Additionally, hydrogen production would have to increase by many orders of magnitude to have ample supply to match the current production output of natural gas-fueled turbines. Duke Energy will continue to monitor hydrogen technology, both production and generation, to prepare for its potential future use as a natural gas fuel substitute.

Additional Storage technologies continue to be developed and pursued by a variety of companies. The range of technologies is vast and include non-lithium-ion batteries, mechanical storage, thermal storage, and variants of pumped hydro storage. Although some storage technologies passed the technology screening, the majority are still in a pre-commercial status. These technologies continued to be studied as future options for generation and include lead acid batteries, sodium-sulfur batteries, metal-air batteries, subterranean pumped storage, gravitational energy, hydrogen, flywheel energy, liquid air energy, chilled water, molten salt, silicon, concrete, sand, and phase change storage. Duke Energy will continue to monitor the developments and pilots of the various storage options to determine which designs have reached commercial status.

A brief explanation of the technology additions for 2020 compared to the 2018 Integrated Resource Plan submittal and the basis for their inclusion follows:

Compressed Air Energy Storage (CAES) offers an additional method of storage over longer durations than typically found in batteries. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30-years. CAES has two primary application methods: diabatic and adiabatic. To utilize CAES, the project needs a suitable storage site, which is typically either a salt cavern or mined hard-rock cavern. Salt caverns have been preferred due to the low cavern construction costs. However, mined hard-rock caverns are now a viable option in areas that do not have salt formations with the use of hydrostatic compensation to increase energy storage density and reduce the cavern volume required. This change to allow mined hard-rock caverns created the potential for CAES in the Carolinas. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir. Energy is then recaptured by releasing the compressed air, heating it, and generating power as the heated air travels through an expander.

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

Although flow batteries' capital costs project to be higher than Li-Ion batteries, flow batteries project to become most effective as the duration of the battery is increased due to energy capacity being dictated primarily by the size of the tanks. Therefore, flow batteries have been included in the technology options as a longer duration storage option.

Offshore Wind is a developing technology in the United States but internationally has become a mature technology. Offshore wind farms have been installed in the oceans off European shores since the 1990s and continue to be an important source of energy in that market. There are several projects in various phases of development in U.S. coastal waters, and more are anticipated as technology and construction advancements allow for installation in deeper waters farther offshore. The Block Island project developed by Deepwater Wind is the first to reach commercial operation, and Duke Energy Renewables is performing remote monitoring and control services for the project. This 30 MW project is located about 3 miles off the coast of Rhode Island.

Duke Energy and NREL studied the potential for offshore integration off the coast of the Carolinas in March 2013. In 2015, the U.S. Bureau of Ocean Energy Management (BOEM) completed environmental assessments at three potential Outer Continental Shelf (OCS) sites off the coast of North Carolina. In March 2017, BOEM administered a competitive lease auction for wind energy in federal waters and awarded Avangrid Renewables the rights to develop an area off the shores of Kitty Hawk. Avangrid has plans for a project that may be as large as 2,400 MW.

Several coastal states including New York, New Jersey, Maryland, Massachusetts, Connecticut, California, Rhode Island, Delaware, and Virginia have been forecasted to have projects developed. New York has an Offshore Wind Master Plan aimed at 2,400 MW of offshore projects by 2030, and Statoil is developing the 1,500 MW Empire Wind project near New York City, aiming for completion in 2025.

The unique constraints of the industry and the increasingly competitive global market are driving R&D improvements that allow wind farms to be sited farther offshore. Installation and siting require careful consideration to bathymetry and offshore construction concerns, but siting is further complicated by shipping lanes, fishing rights, wildlife migration patterns, military operations, and other environmental concerns. Plus, coastal residents and tourists prefer an unobstructed ocean view, so the larger turbines require longer distances to keep them out of sight.

Although technology costs still remain high for offshore wind, the technology is being evaluated as an additional renewable option. The profile of offshore wind allows for a higher capacity factor in the Carolinas than onshore wind, and the profile also compliments solar energy.

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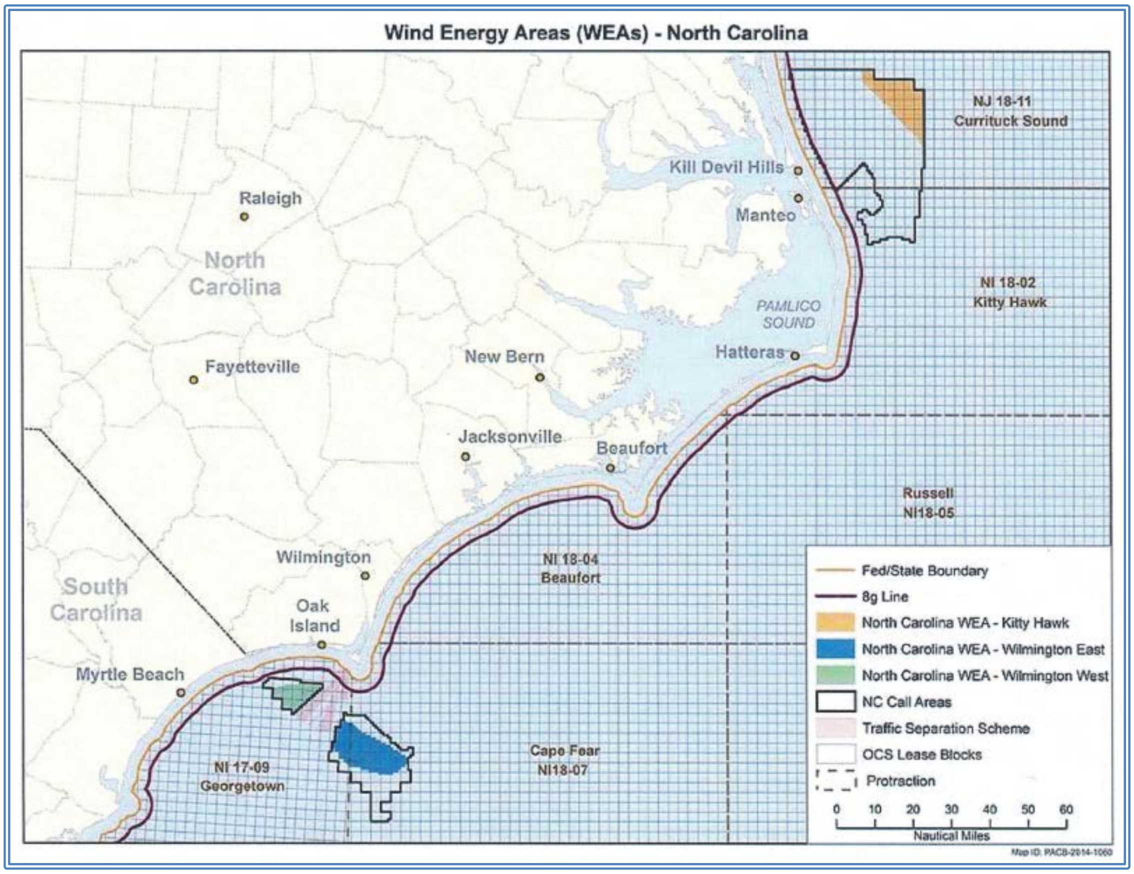
FIGURE G-3

NC WIND ENERGY AREAS (WEAS) (DEVELOPED IN JOINT VENTURE BY DUKE ENERGY AND NREL)



GENERATION FLEXIBILITY AND DUKE ENERGY CLIMATE PLAN

As more intermittent generation becomes associated with Duke's system there is a greater need for generation that has rapid load shifting and ancillary support capabilities. This generation would need to be dispatchable, possess desirable capacity, and ramp at a desired rate. Some of the technologies that have 'technically' screened in possess these qualities or may do so in the near future. Effort is being made to value the characteristics of flexibility and quantify that value to the system. As a result of the flexible generation need, some features of 'generic' plant's base designs have been modified to reflect the change in cost and performance to accomplish a more desired plant characteristic to diminish the impact of the intermittent generation additions.

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Additionally, in 2020 Duke Energy released a revision to its previous Climate Report with aggressive goals to reduce output from its generating facilities by 2030 and even deeper reductions by 2050. Duke Energy concluded that it would need new technologies that have not yet reached commercialization status that performed as Zero-Emitting Load-Following Resources (ZELFR). The load-following requirement comes from the flexibility need described above, and the zero-emission portion is to help Duke Energy meet its future climate goals.

Duke Energy is evaluating several generation technologies that are considered pre-commercial to meet the ZELFR need. Technologies considered typically fall under the broad categories of advanced nuclear, advanced renewables, advanced transmission and distribution, biofuels, carbon capture utilization and sequestration, fuel cells, hydrogen, long duration energy storage, and supercritical CO_2 Brayton Cycle. All of these technologies are expected to help Duke Energy meet future carbon reduction goals if they reach commercial status and are economically competitive.

Duke Energy expects multiple technologies to be required to meet its carbon reduction goals, and therefore Duke Energy is considering potential paths to help move these technologies towards commercialization. One such effort Duke Energy is pursing is the recently announced partnership with two advanced reactor developers on DOE's Advanced Reactor Deployment Program to deploy one of the first two advanced nuclear reactors. Another effort underway is the collaborative work with Siemens as part of DOE's Energy Storage for Fossil Generation Program to evaluate the possibility of hydrogen co-firing at the Combined Heat and Power Plant on Clemson's campus. Duke Energy recognizes the potentially long commercialization timeframe for some of these technologies and will continue to pursue efforts to move these important technologies forward.

Although these technologies all screen out in the process due to their commercial status, Duke Energy will continue to follow a wider range of technologies to meet these future generation needs.

ECONOMIC SCREENING

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves, also referred to as *busbar* curves. By definition, the *Busbar* curve estimates the revenue requirement (i.e. life-cycle cost) of power from a supply option at the "busbar," the point at which electricity leaves the plant (i.e. the high side of the step-up transformer). Duke Energy provides some additional evaluation of a generic transmission and/or interconnection cost adder associated with each technology.

The screening within each general class of busbar (Baseload, Peaking/Intermediate, Renewables and Storage), as well as the final screening across the general classes, uses a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy. Again, for the 2020 IRP year, Duke Energy has provided an additional set of busbar curves to represent Storage technology comparisons. As Storage technologies are not traditional generating resource options, they should be compared independently from generating resources. In addition, there has been no *charging* cost associated with the storage busbar buildup. This charging cost is excluded as it is dependent upon what the next marginal unit is in the dispatch stack as to what would be utilized to "charge" the storage resource. For resource options inclusive of or coupled with storage, it is assumed that the storage resource is being directly charged by the generating resource (i.e. Solar PV plus Battery Storage option).

This screening (busbar) curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors. The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some technologies have screening curves limited to their expected operating range on the individual graphs. Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

The Company selected the technologies listed below for the screening curve analysis. While future carbon emission constraints may effectively preclude new coal-fired generation, Duke Energy has included ultra-supercritical pulverized coal (USCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1400 pounds/net MWh capture rate as options for baseload analysis. 2020 additions include Offshore wind, additional Lithium Ion Battery Storage options, Flow Battery Storage, and Advanced Compressed Air Energy Storage.

DISPATCHABLE (WINTER RATINGS)			
BASELOAD	**PEAKING / INTERMEDIATE**	**STORAGE**	**RENEWABLE**
601 MW, 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	18 MW, 2 x Reciprocating Engine Plant	10 MW / 10 MWh Lithium-ion Battery	75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
1,224 MW, 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	15 MW Industrial Frame Combustion Turbine (CT)	10 MW / 20 MWh Lithium-ion Battery	5 MW Landfill Gas
782 MW Ultra-Supercritical Pulverized Coal with CCS	192 MW, 4 x LM6000 Combustion Turbines (CTs)	10 MW / 40 MWh Lithium-ion Battery	**NON- DISPATCHABLE (WINTER RATINGS)**
557 MW, 2x1 IGCC with CCS	201 MW, 12 x Reciprocating Engine Plant	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
720 MW, 12 Small Modular Reactor Nuclear Units (NuScale)	752 MW, 2 x J-Class Combustion Turbines (CTs)	50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
2,234 MW, 2 Nuclear Units (AP1000)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	20 MW / 160 MWh Redox Flow Battery	75 MW Fixed-Tilt (FT) Solar PV
9 MW Combined Heat & Power (Reciprocating Engine)		250 MW / 4,000 MWh Advanced Compressed Air Energy Storage	75 MW Single Axis Tracking (SAT) Solar PV
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

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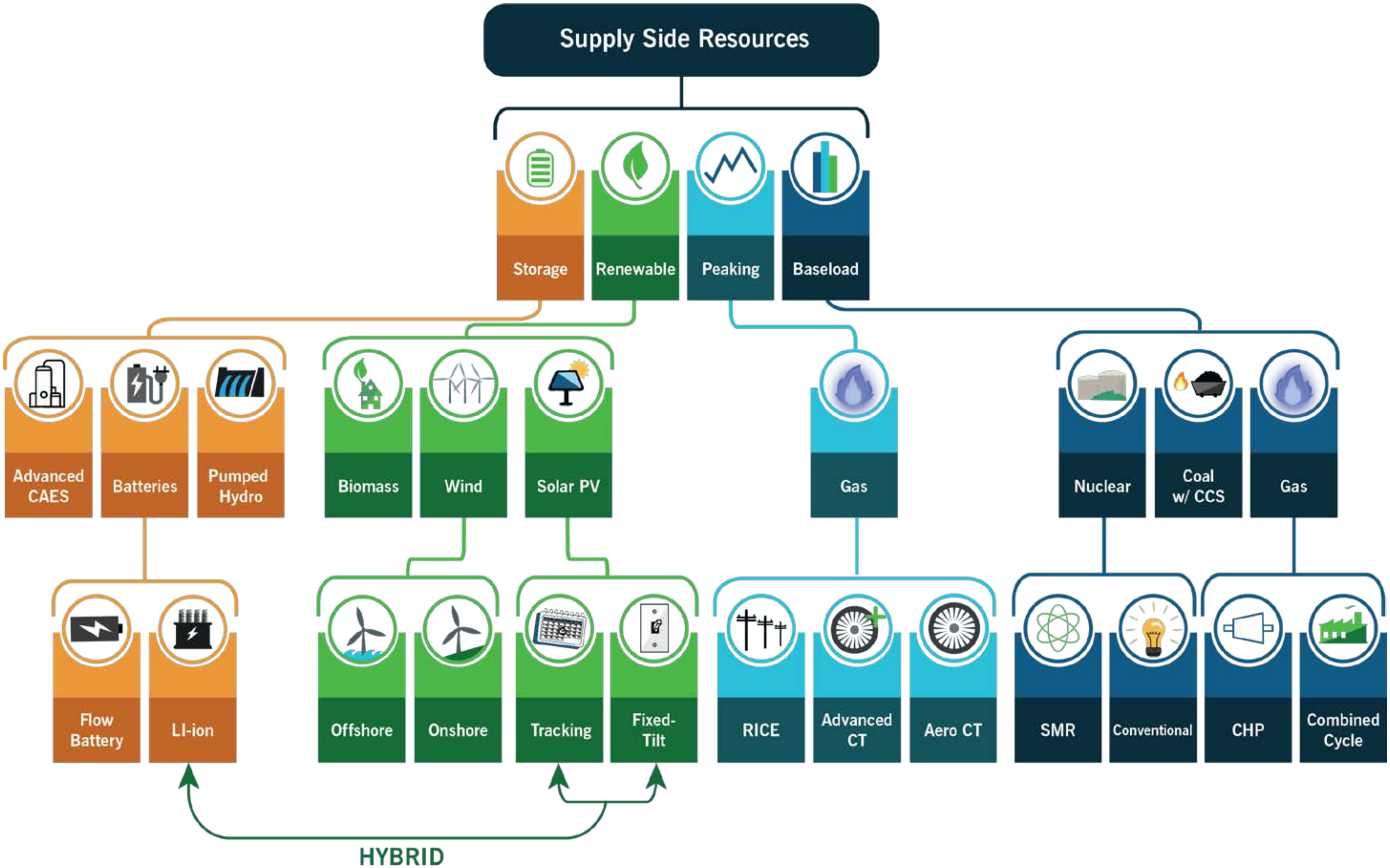
FIGURE G-4

DUKE ENERGY, SCREENED-IN SUPPLY SIDE RESOURCE ALTERNATIVES



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INFORMATION SOURCES

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include a variety of internal departments at Duke Energy. In additional to the internal expertise, the following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific but generally reflect the costs and operating parameters for installation in the Carolinas. Finally, every effort is made to ensure that capital, operating and maintenance costs (O&M), fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs (i.e. No CO_2, With CO_2) in the four major categories defined (Baseload, Peaking/Intermediate, Renewables, Storage).

CAPITAL COST FORECAST

A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs but the costs of all resource technologies technically screened in. The Technology Forecast Factors were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides cost projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.

Using 2020 as a base year, an " annual cost factor is calculated based on the change from a base year for the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2018, April 2019)

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From *NEMS Model Documentation 2018, April 2019*:

> *"Uncertainty about investment costs for new technologies is captured in the ECP [Electricity Planning Submodule] using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.*
>
> *Learning factors represent reductions in capital costs as a result of learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity."*

The resulting Forecast Factor Table developed from the EIA technology maturity curves for each corresponding technology screened is depicted in Table G-1.

TABLE G-1

SNAPSHOT FROM FORECAST FACTOR TABLE BY TECHNOLOGY (EIA - AEO 2020)

YEAR	FRAME CT	AERO CT	NUCLEAR	BATTERY STORAGE	1X1 COMBINED CYCLE	ONSHORE WIND
2020	1.000	1.000	1.000	1.000	1.000	1.000
2021	0.985	0.987	0.984	0.812	0.987	0.987
2022	0.970	0.973	0.967	0.718	0.973	0.973
2023	0.950	0.961	0.950	0.640	0.961	0.961
2024	0.901	0.953	0.920	0.625	0.953	0.953
2025	0.873	0.945	0.909	0.609	0.945	0.945
2026	0.852	0.937	0.898	0.594	0.937	0.937
2027	0.831	0.928	0.886	0.579	0.927	0.928
2028	0.815	0.918	0.874	0.563	0.918	0.918
2029	0.803	0.907	0.861	0.546	0.907	0.907
2030	0.789	0.896	0.847	0.530	0.896	0.896

SCREENING RESULTS

The results of the screening within each category are shown in the figures below. Results of the baseload screening show that natural gas combined cycle generation is the least-cost baseload resource. With lower gas prices, larger capacities and increased efficiency, natural gas combined cycle units have become more cost-effective at higher capacity factors in all carbon scenario screening cases (i.e. No CO_2 and With CO_2). Although CHP can be competitive with CC, it is site specific and requires a local steam and electrical load. Carbon capture systems have been demonstrated to reduce coal-fired CO_2 emissions to levels similar to natural gas and will continue to be monitored as they mature; however, their current cost and uncertainty of safe, reliable storage options has limited the technical viability of this technology in Duke Energy territories.

The peaking technology screening included F-frame and J-Frame combustion turbines, fast start aero-derivative combustion turbines, and fast start reciprocating engines. The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires the fast start capability of the aero-derivative CTs or reciprocating engines. Reciprocating engine plants offer the lowest heat rates and fastest start times among simple cycle options. Simple cycle aeroderivative gas turbines remain in close contention with reciprocating engines. Should a need be identified for one of these two types of resources, a more in-depth analysis would be performed.

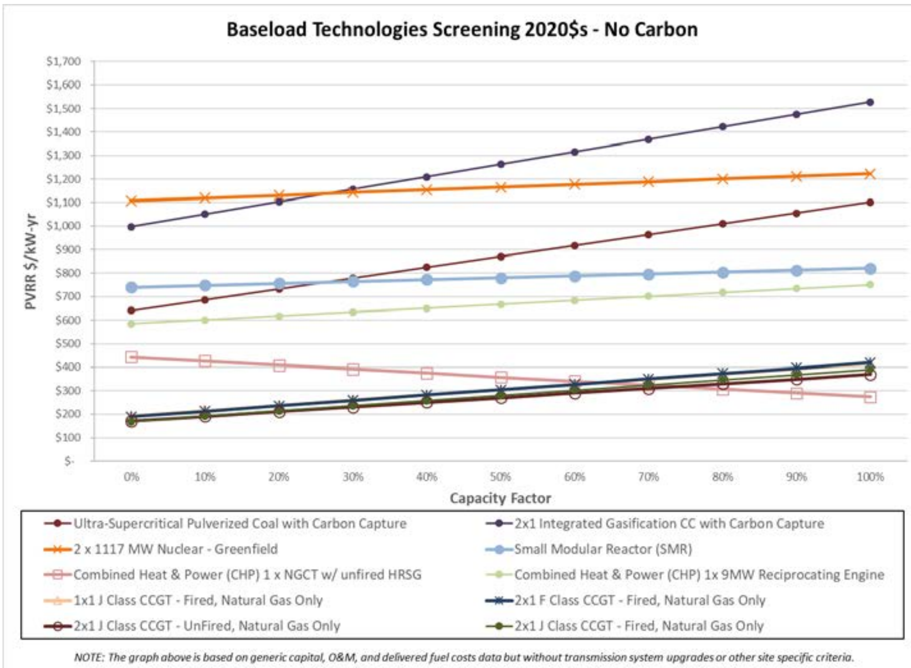
The renewable screening curves show solar continues to be a more economical alternative than other renewable resource options. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas and biomass projects are limited based on site availability but are dispatchable. Landfill gas is not shown in the busbar curve for renewables as the options are limited since most sites have already been transacted with. Although solar PV prices have become competitive with conventional generators, the lack of dispatchability and low capacity factor does not allow it to be a baseload resource.

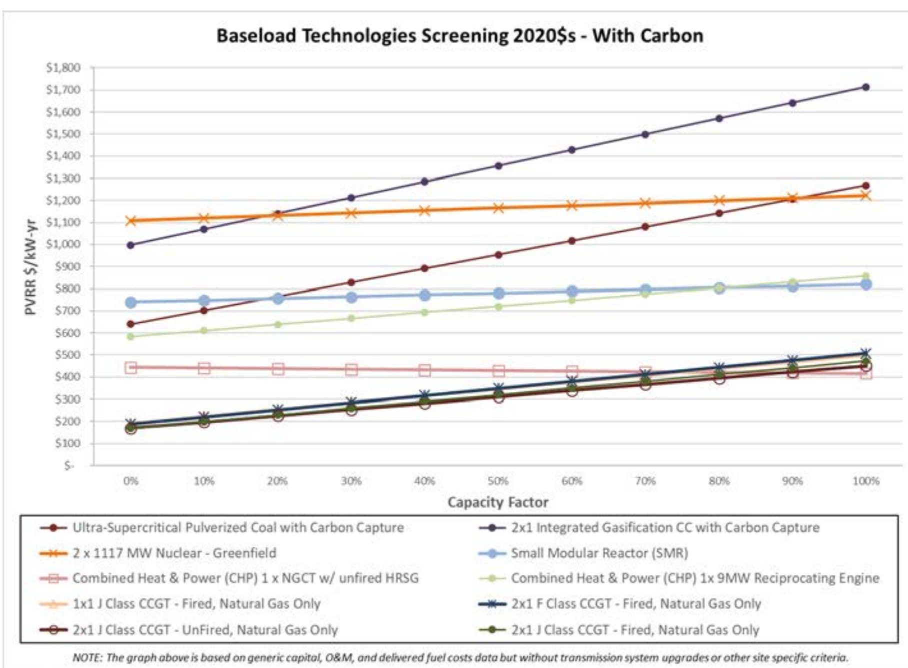
Energy storage has become an increasingly important asset as companies add more variable resources to their portfolio. Energy storage can provide a variety of benefits to the grid and overall resource portfolio. Additional information on energy storage can be found in Appendix H. For the screening results, the lowest $/kW option for energy storage was 1-hour duration Li-Ion storage as expected. However, batteries have a variety of use cases and longer duration storage can be more useful than shorter duration storage in certain cases. Additionally, the $/kWh decreases as the duration of the storage increases. So, although the 1-hour duration Li-Ion battery storage asset had the lowest screening cost, the specific application of the storage option will determine which storage option is the best fit for its use case.

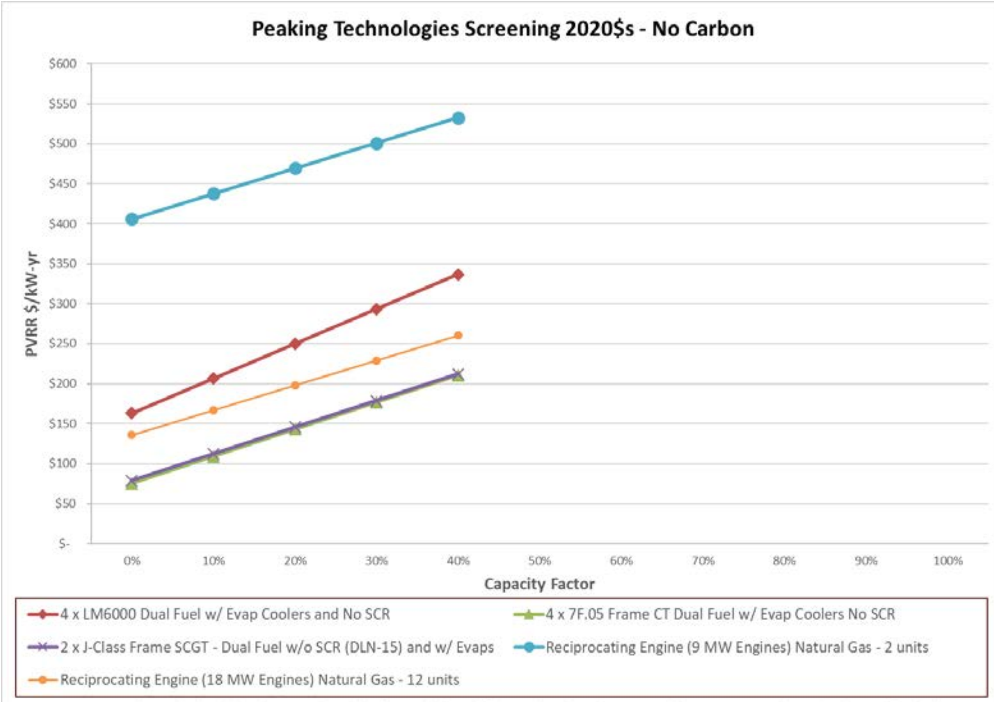
The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.

SCREENING CURVES

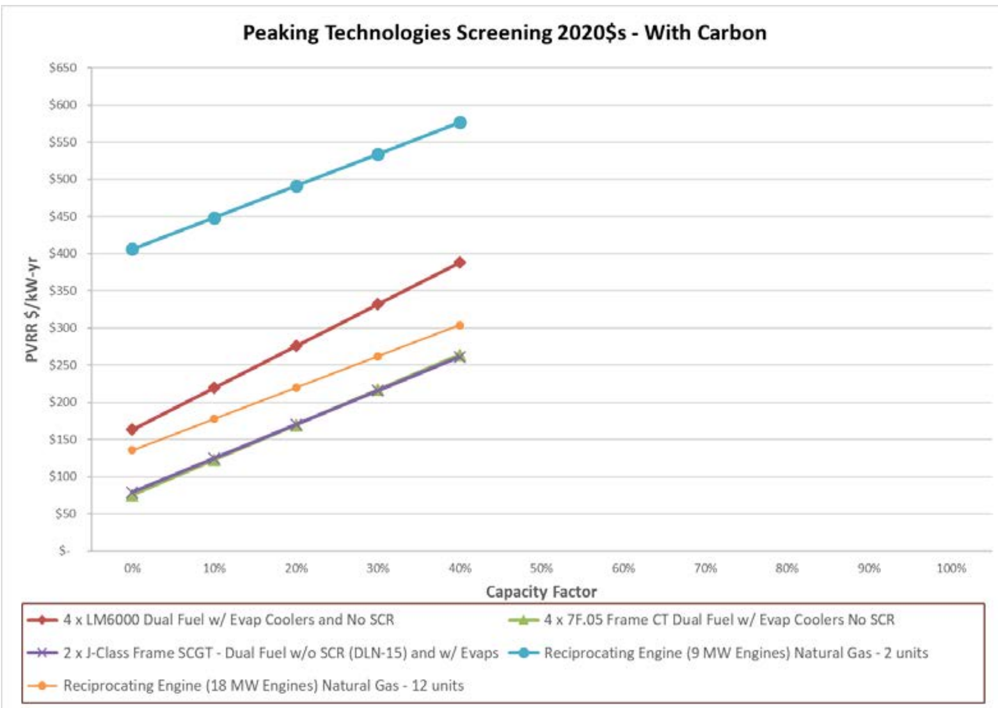
The following pages contains the technology screening curves for baseload, peaking/intermediate, renewable and storage technologies.



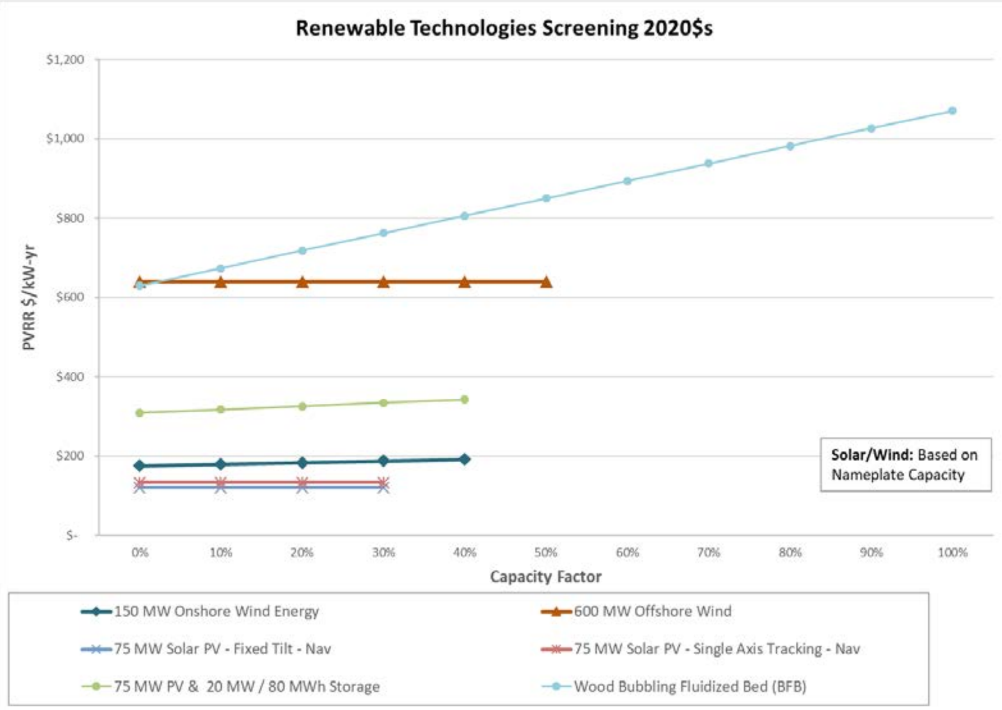




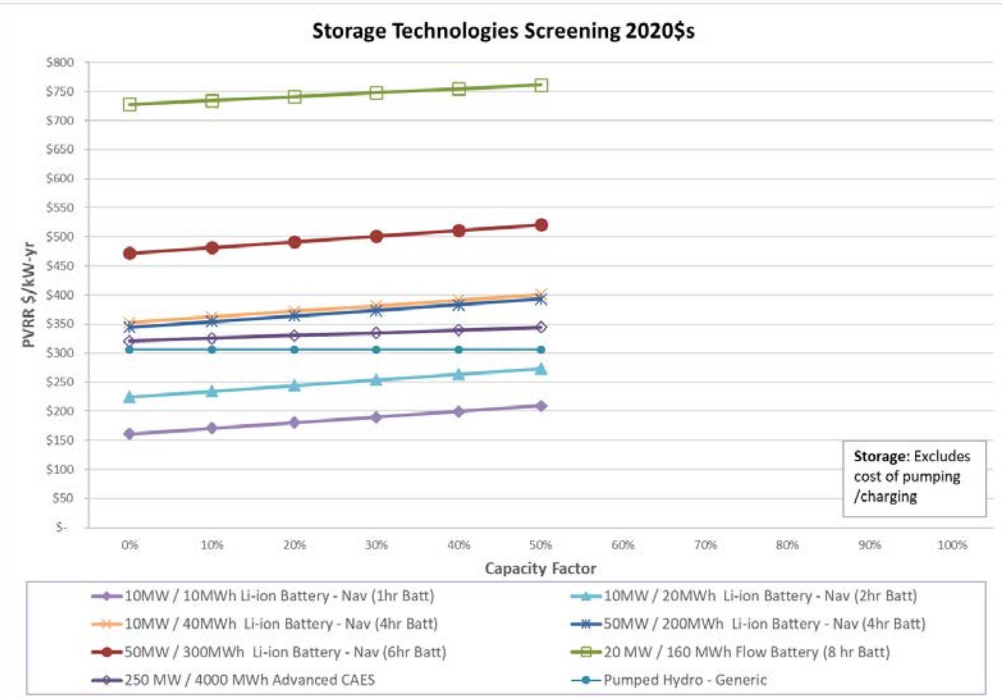
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.

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ENERGY STORAGE

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APPENDIX H: ENERGY STORAGE

Battery storage is expected to play an important role in meeting future needs on the DEC system. As discussed in Chapter 6, battery storage can provide multiple services. For purposes of the 2020 IRP, the Company considered capacity, energy arbitrage, and ancillary service benefits when valuing battery storage. Additionally, the Company conducted a thorough review of battery cost and operating assumptions modeled in the 2020 IRP. Benchmarking battery storage costs across publications is difficult, and oftentimes not possible, due to disparate definitions and incomplete documentation. Some publications do not include the full cost that would be needed to construct a battery storage system that would meet the requirements of a manufacturer's warranty and the needs of the Utility over the life of the asset. For this reason and to provide transparency of the cost estimating process, the Company is detailing the battery storage assumptions used in the 2020 IRP below.

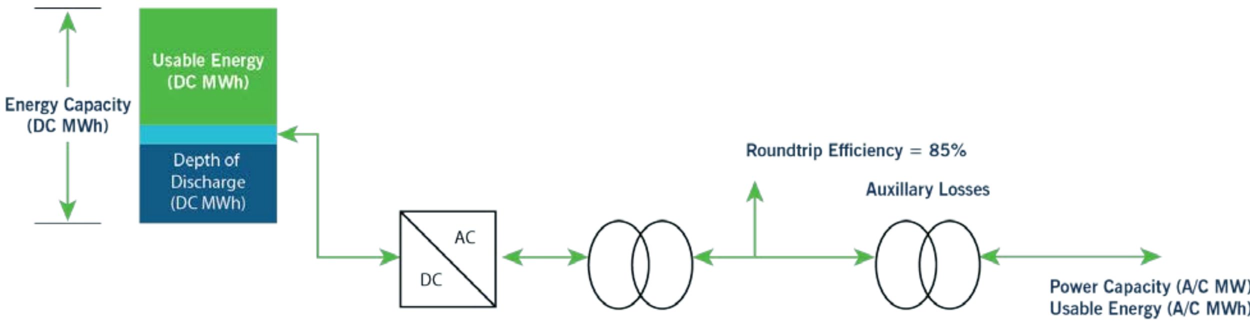
Finally, in order to appropriately estimate the capacity value battery storage can provide, the Company hired a third-party consultant to conduct an Effective Load Carrying Capability ("ELCC") study to quantify the contribution to winter peak demand that battery storage could provide in DEC. The results of the ELCC study are described in the following sections and the Battery Storage ELCC study has been filed along with the IRP filing.

BATTERY STORAGE TERMINOLOGY AND OPERATING ASSUMPTIONS

Some of the terminology that the Company uses to describe batteries in the IRP is detailed below. Importantly, while many of the terms and definitions below are standard across the industry, some of the terms are specific to how battery storage is described in this IRP and may not match what is described in other publications. Where appropriate, definitions that are taken directly from outside publications are cited. The following is a diagram of a standalone battery storage system that is modeled in the 2020 IRP.

FIGURE H-1

SIMPLIFIED BATTERY STORAGE SYSTEM MODELED IN 2020 DEC IRP



- **Battery size** – Battery sizing is generally provided in capacity and energy values or capacity value and duration. The terms "capacity", "energy", and "duration" are discussed below. An example of battery size nomenclature is "50 MW / 200 MWh" which represents a 50 MW battery with a 4-hour duration.

- **Capacity** – Generally referred to as "power capacity" in the industry and represents the total possible instantaneous discharge capability of the battery storage system, or the maximum rate of discharge the battery can achieve starting from a fully charged state.[1] The Company measures power capacity at the point of interconnect to the transmission system and the units are "MW AC." The IRP represents the cost of a battery in $/MW where the numerator, or dollars, is the total cost of the battery system and the denominator is the power capacity in MW AC of the system. The components of the total cost of the battery system are described in further detail below.

- **Energy** – The energy that a battery can hold can be represented differently between publications which can make comparing costs between sources of data difficult. For the purposes of this IRP, the Company considers energy in the following manners:

    - **Usable Energy** – Refers to the amount of energy that can be discharged at the point of interconnection over the duration of the battery. Usable energy can be described in units of "MWh AC" or "MWh DC." When the Company discusses the cost of a battery on a $/MWh basis, the numerator is the total cost of the battery system and the denominator is the usable energy in units of MWh AC.

[1] https://www.nrel.gov/docs/fy19osti/74426.pdf,

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- **Depth of Discharge (DoD) –** "Indicates the percentage of the battery that has been discharged relative to the overall [energy] capacity of the battery."[2] In the 2020 IRP, this number represents the amount of energy that must remain, unused, in the battery to satisfy the warranty of the battery and/or allow the battery to complete the expected number of cycles over the life of the asset. For instance, the Company uses a 20% depth of discharge limit which simply means the battery cannot discharge more than 80% of its energy capacity. Some publications only provide battery costs based on the usable energy of the battery thereby ignoring the DoD; however, the Company calculates the cost of a battery based on the energy capacity, which includes the DoD limitation.

- **Energy Capacity –** The total amount of energy that can be stored or discharged by the battery storage system.[3] In the diagram above, energy capacity is the sum of the usable energy and the depth of discharge limit. Energy capacity is defined in units of "MWh DC." The Company did not include additional costs for other "unused" energy required to maintain the contracted usable energy of the battery, such as additional energy capacity to account for DC or AC losses that occur during charge and discharge of the battery. However, within the production cost model, the Company does account for the production cost impacts of losses on roundtrip efficiency of the battery as discussed below.

- **Duration –** "Amount of time storage can discharge at its power capacity. "[4] For example, a battery with 50 MW of power capacity and 200 MWh of usable energy capacity will have a storage duration of 4 hours.

- **Roundtrip Efficiency –** "Measured as a percentage, is a ratio of the energy charged to the battery to the energy discharged from the battery. It can represent the total DC-DC or AC-AC efficiency of the battery system, including losses from self-discharge and other electrical losses."[5] The Company uses A/C - A/C efficiency as the production cost models only consider the charging/discharging at the point of interconnect to the power system. The Company

[2] https://news.energysage.com/depth-discharge-dod-mean-battery-important/#:~:text=A%20battery's%20depth%20of%20discharge,DoD%20is%20approximately%2096%20percent.
[3] U.S. Battery Storage Trends, U.S. Energy Information Administration, May 2018.
[4] https://www.nrel.gov/docs/fy19osti/74426.pdf.
[5] https://www.nrel.gov/docs/fy19osti/74426.pdf.

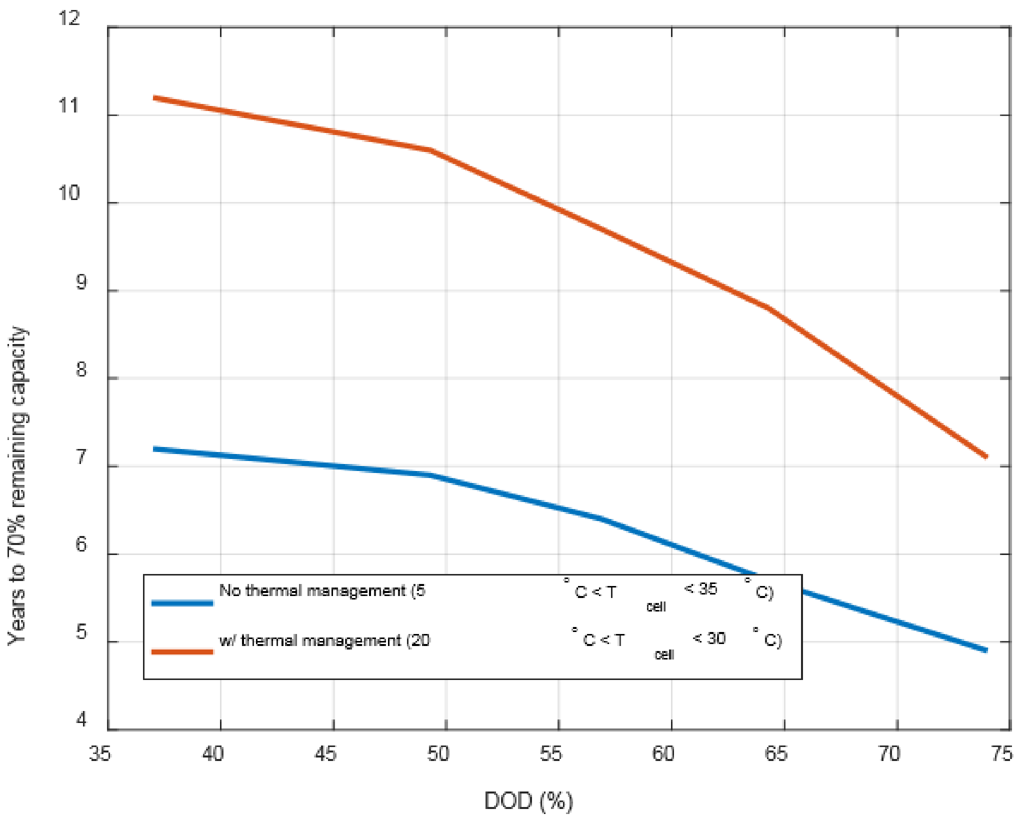
assumed a roundtrip efficiency of 85% for all lithium-ion (Li-ion) batteries modeled in the 2020 IRP.

- **Auxiliary Losses -** Included as part of other electrical losses in the calculation of round-trip efficiency and can include power required for HVAC systems associated with the battery storage system.

- **Degradation –** The loss of energy capacity of a battery storage system overtime. "Degradation of lithium-ion batteries is impacted by several variables. Known drivers of degradation include: temperature of operation, average state of charge over its lifetime, and depth of charge-discharge cycles."[6] Figure 2, sourced from NREL's "Life Prediction Model for Grid Connected Li-ion Battery Energy Storage System" demonstrates the effects that DoD and temperature management of the battery storage system can have on degradation.

[6] https://www.energy-storage.news/blogs/is-that-battery-cycle-worth-it-maximising-energy-storage-lifecycle-value-wi#:~:text=Battery%20storage%20degradation%20typically%20manifests,need%20for%20replacement%20of%20batteries.

FIGURE H-2
IMPACT OF BATTERY OVERSIZING AND THERMAL MANAGEMENT ON LIFETIME FROM NREL[7]



- **Battery Augmentation –** As a battery storage system experiences degradation, battery cells can be replenished on a regular, or semi-regular, basis to maintain the usable energy of the battery storage system. This strategy to counteract degradation leads to lower initial capital costs but incurs higher on-going costs throughout the life of the asset. For IRP purposes, the Company assumes a Battery Augmentation strategy to minimize total costs over the 15-year assumed life of the battery asset, while recognizing that this approach does present some challenges with maintaining stable performance of the system.

- **Overbuild –** Refers to an increase in the nameplate energy capacity to account for expected degradation. As an alternative strategy to augmentation, the battery storage system can

[7] https://www.nrel.gov/docs/fy17osti/67102.pdf.

initially be physically oversized beyond depth of discharge limits to account for degradation. This strategy yields higher initial capital costs but lower on-going costs versus an augmentation strategy.

BATTERY STORAGE COST ASSUMPTIONS

Battery storage costs have been declining rapidly over the last several years, and they are expected to continue declining for the foreseeable future. In fact, the Company assumes that battery prices will drop by nearly 50% over the next 9 years.[8]

The Company's capital cost assumptions are developed by a third party and are benchmarked against both internal and external sources. Often, the Company's prices appear higher than published numbers. As discussed above, there are several factors that can drive this difference including:

- The Company calculates the cost of a battery storage device assuming a 20% DoD limit while other publications likely only calculate the cost of the battery based on the rated energy of the battery from their information sources, which often do not specify whether their energy rating factors in DoD. In cases where the energy rating does not account for DoD, the cost of the battery can differ by over 10%.

- The Company assumes interconnection costs based on historical costs on the DEC system. Other publications may include lower interconnection costs or may not account for interconnection costs altogether.

- Because the Company expects to rely on these assets for at least 15-years to provide reliable capacity and energy to its customers on a real-time basis, some of the Company's assumptions of software and controls may lead to higher capital costs than a device that is designed to provide capacity and energy with lower reliability standards or on a more standard schedule.

- Similarly, the Company may be including more expensive HVAC and fire detection and suppression assumptions when calculating the cost of the battery storage system. It is the Company's belief that this cost is warranted for safety and protection of employees as well as the assets.

[8] Real 2020$; prices drop by 34% in nominal terms assuming 2.5% inflation rate.

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- Due to low installed capacity and limited operational experience with battery storage on the DEC system, the Company assumes that system integration costs of a battery would be on the level of a custom application rather than a basic, or turnkey, level of cost. It is likely however, that as battery storage becomes more pervasive on the DEC system, system integration costs will decline, and battery storage costs could decline further than the near 50% decline already assumed in the IRP. The Company will monitor developments in this area and adjust as appropriate in future IRPs.

As stated previously, it is very difficult to determine what is included in the cost assumptions for battery storage in publications, particularly with regards to software and controls, HVAC, fire detection and suppression, and system integration costs. The following are the assumptions the Company includes for the percent contribution of costs from various components of a battery storage system along with the projected cost trend through 2029 in nominal terms assuming 2.5% inflation.[9]

TABLE H-1

COST COMPONENTS OF BATTERY STORAGE IN 2020 IRP

COMPONENT	% OF TOTAL COST[10]	PROJECTED COST TREND THROUGH 2029
Battery Pack	53%	-51%
Power Electronics	3%	-40%
Software and Controls	1%	-8%
Balance of Plant	9%	-15%
Systems Integration	15%	-30%
Site Installation	8%	3%
Project Development Fees	6%	-24%
Interconnection Fees	5%	25%

As further context to the above cost allocations and assumptions, EPRI recently conducted a survey of its members regarding cost assumptions of battery storage. Many members use public sources

[9] Initial value based on 2020 cost of a 50 MW / 200 MWh battery storage system in the 2020 IRP.
[10] Values based on total cost without owner's costs. Owner's costs are consistent with the costs incurred during the development of the Company's previous storage projects.

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such as NREL, Lazard, and EPRI, in addition to commercial third-party forecasts and in-house SME input, when developing battery storage price forecasts. Importantly, members do not simply rely on published numbers without making some adjustments. Members identified adding costs for items such as interconnection, A/C balance of plant, substation, land, and civic infrastructure. Nearly half of respondents factor in costs associated with a state of charge (SOC) window or depth of discharge limitation when developing cost estimates. Finally, one cost that DEC does not account for are end-of-life costs for disposal and recycling of battery storage components. Just over half of respondents account for these costs and the Company will evaluate adding end-of-life costs in future IRPs.

EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) OF BATTERY STORAGE

The Company commissioned Astrapé Consulting, a nationally recognized expert in the field, to conduct a Storage Effective Load Carrying Capability (ELCC) Study of battery storage to determine the capacity value that short-duration storage can provide towards meeting DEC's winter peak demand. The ELCC study evaluated both standalone storage, as well as, DC coupled solar plus storage over a range of storage penetrations, durations, and solar levels. The results of the study are highlighted below, and the full report is filed with the IRP as Attachment 4. Importantly, the study confirmed that initial additions of storage can provide nearly 100% contribution to winter peak, however the ELCC contribution of energy storage decreases rapidly with increasing penetration of battery storage as is the case with any energy limited resource.

STANDALONE STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study under a base level of solar (2,700 MW) and a high level of solar (4,500 MW).

TABLE H-2

STANDALONE STORAGE RUN MATRIX FOR ELCC STUDY

Duration / Cumulative Battery Capacity	STANDALONE BATTERY DURATION (HRS) 2	4	6
400 MW			
800 MW (incr 800)			
1,200 MW (incr 800)			
2,000 MW (incr 800)			

The sensitivities analyzed in the matrix above were conducted separately for each battery duration. For example, 6-hour batteries were studied as if there were no 4-hour or 2-hour batteries on the DEC system. In this manner, the ELCC represents the value of a 6-hour battery without the impacts of other incremental storage on the system. An additional sensitivity was analyzed which studied the impacts of 6-hour storage if up to 800 MW of 6-hour storage were placed on the system *after* 2,000 MW of 4-hour storage were already operating in DEC.

The ELCC of standalone storage was determined separately under the following three conditions:

- Preserve Reliability – Assumes full control of the battery and only dispatches the battery during emergency events to avoid firm load shed, maintains charge at all times possible. Results in highest possible capacity value but low economic value.

- Economic Arbitrage – Assumes DEC maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.

- Fixed Dispatch – Assumes DEC has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEC did not have dispatch rights to the storage asset.

The following three figures depict the capacity value of 2-hour, 4-hour, and 6-hour storage under the three operating conditions described above.

FIGURE H-3
AVERAGE CONTRIBUTION TO DEC WINTER PEAK IN PRESERVE RELIABILITY MODE

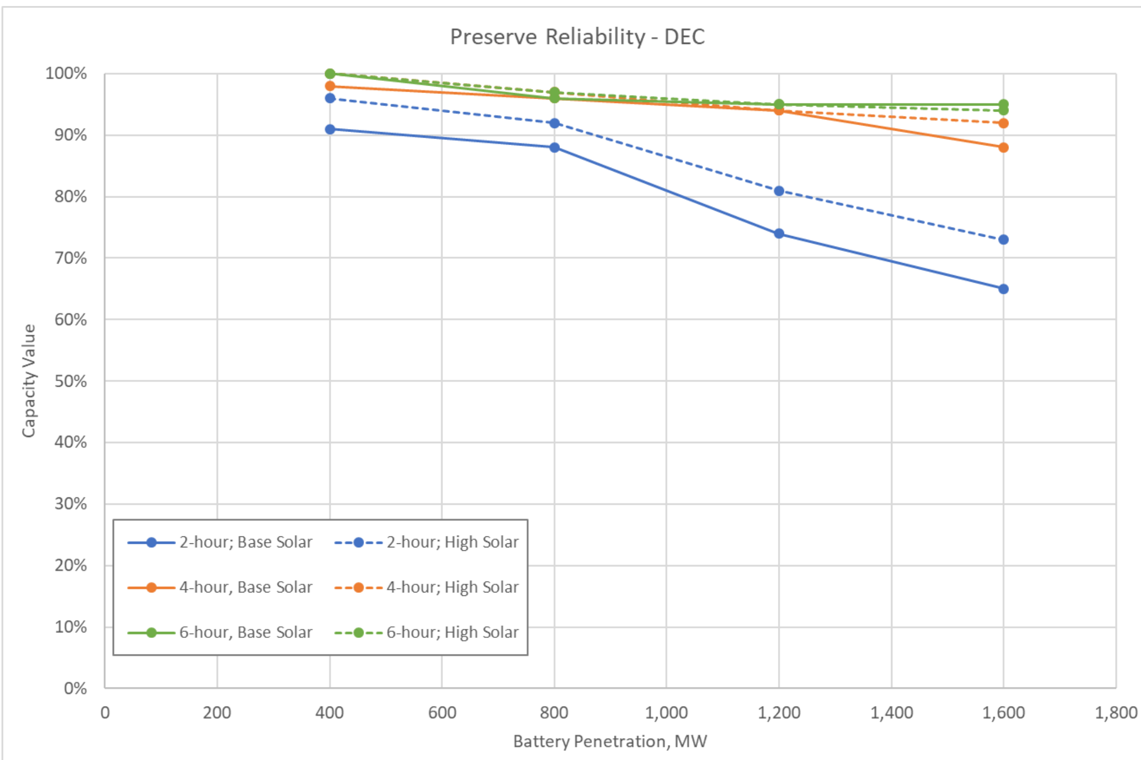

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FIGURE H-4

AVERAGE CONTRIBUTION TO DEC WINTER PEAK IN ECONOMIC DISPATCH MODE

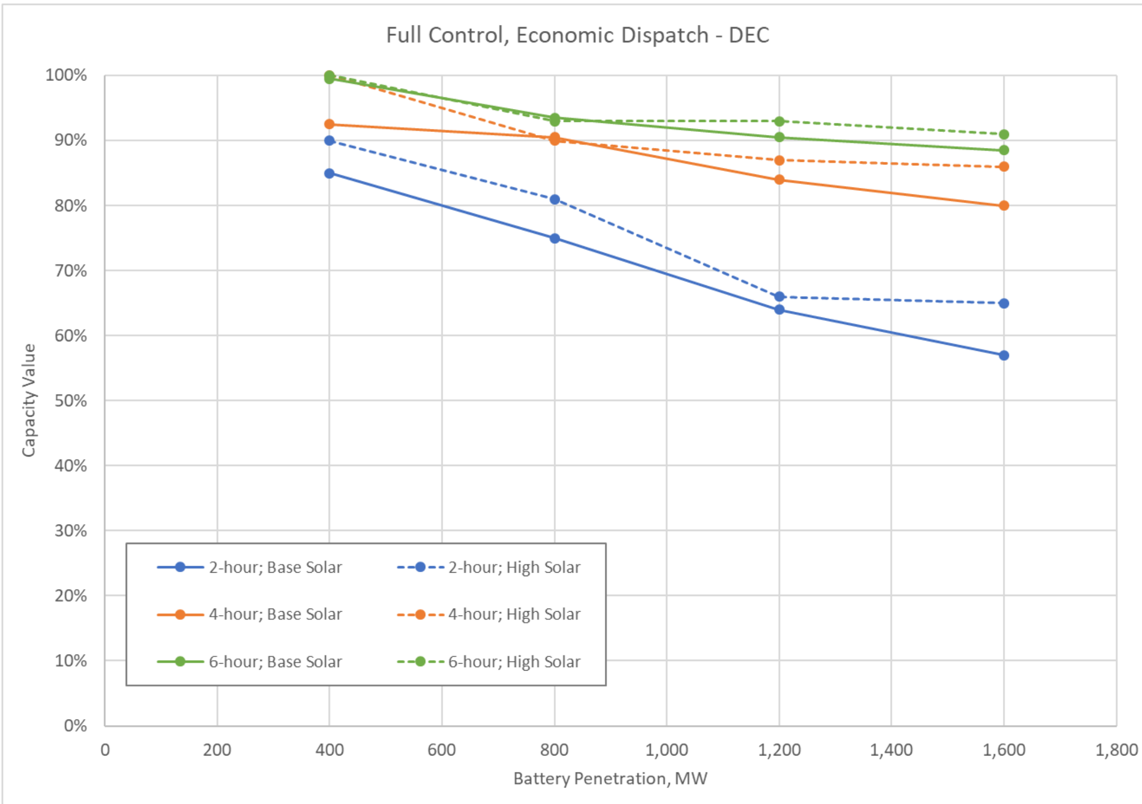

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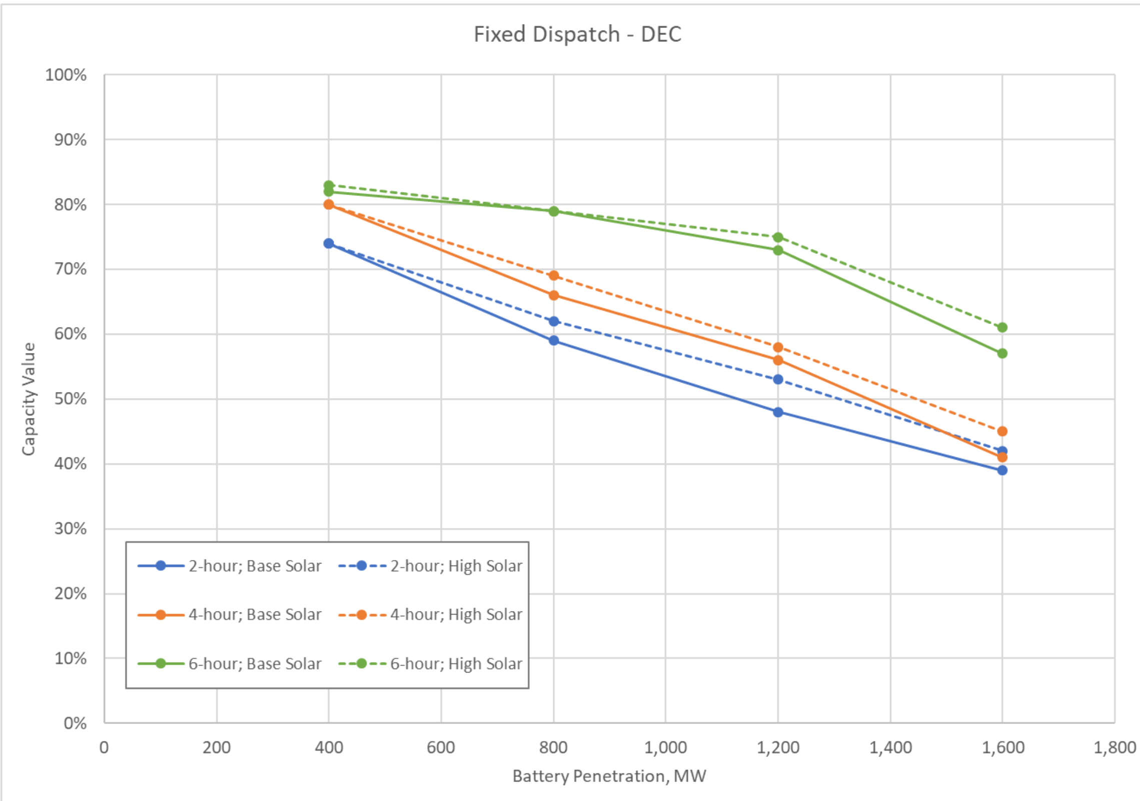
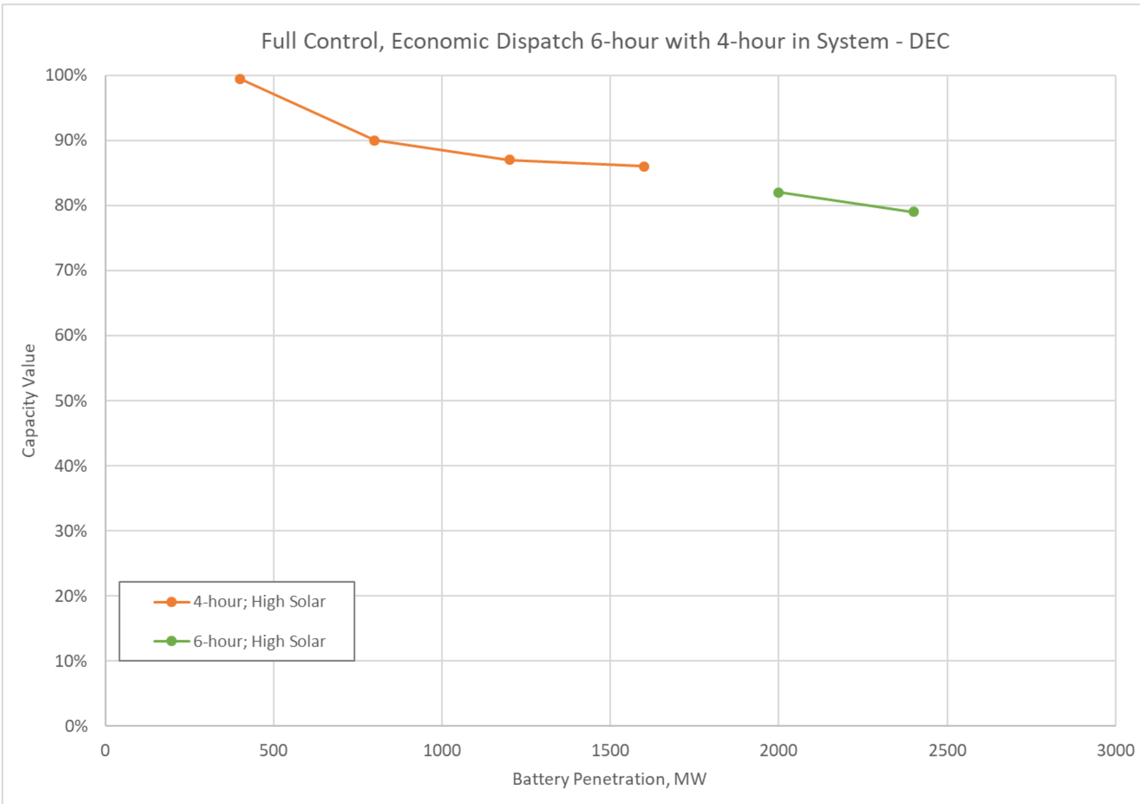
FIGURE H-5

AVERAGE CONTRIBUTION TO DEC WINTER PEAK IN FIXED DISPATCH MODE



The results of the sensitivity of 6-hour storage added after 1,600 MW of 4-hour storage are shown in the following chart.

FIGURE H-6
AVERAGE CONTRIBUTION TO DEC WINTER PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM



Based on the results of the study, DEC made the following assumptions in development of the 2020 IRP:

- **All storage capacity values based on Economic Dispatch** – The IRP model maximizes the value of battery storage by charging the battery with lower cost energy and discharging the stored energy during periods where energy has more value. The model does not maintain full charge in all hours and forego economic benefit to customers to ensure the battery is available to meet demand if a generator on the system experiences an unplanned outage. Similarly, in practice, a board operator does not have perfect foresight of forced outages and would likely use the battery when it is economically prudent based on what they see at the time. Alternatively, as demonstrated in the results above, the value of battery storage for DEC's customers is maximized when the utility maintains dispatch rights for the battery asset. For these reasons, the Company relied on the ELCC results modeled under Economic Arbitrage conditions.

- **Only 4-hour and 6-hour storage considered for standalone storage** – Under all dispatch options, the value of 2-hour storage quickly diminishes as their penetration increases on the system. As shown in Appendix B of the Resource Adequacy report (Attachment III of the IRP), even though most of the LOLH occurs in the hour beginning 7AM, DEC has LOLH over a range of hours in the morning and evening which limits the value that 2-hour storage can provide to the system. Additionally, two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish.

While the above results show the average capacity value attributed to varying levels of storage on the DEC system, the incremental value of adding 400 MW blocks of storage can be calculated from the results. The incremental values are useful when determining the capacity value of the next block of energy storage, particularly when evaluating replacing a CT with a 4-hour battery as discussed in Appendix A and the economic coal retirement discussion Chapter 11. The incremental capacity value of storage assumed in the IRP is shown in the following table.

TABLE H-3

INCREMENTAL CONTRIBUTION TO PEAK FOR 4- AND 6-HOUR STORAGE IN DEC

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
Base Renew	4-hour	0 - 800	90%
		800 - 1,600	70%
	6-hour	0 - 400	100%
		400 - 1,600	85%
High Renew	4-hour	0 - 400	100%
		400 - 1,600	80%
		1,600 - 2,200	70%
	6-hour	0 - 400	100%
		400 - 1,200	90%
		1,200 – 1,600	85%
		1,600 – 2,400	70%

For planning purposes, the Company installed a lower limit of 70% incremental contribution to winter peak before moving to 6-hour storage. In that case, DEC assumed the following incremental contribution to winter peak for 4- and 6-hour storage.

TABLE H-4

INCREMENTAL CONTRIBUTION TO PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
High Renew	4-hour	0 - 400	100%
		400 - 800	80%
		800 – 1,200	80%
		1,200 – 1,600	80%
	6-hour	1,600 – 2,000	70%
		2,000 – 2,400	65%

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SOLAR PLUS STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study assuming a 2-hour or 4-hour battery were coupled with solar.

TABLE H-5
SOLAR PLUS STORAGE RUN MATRIX FOR ELCC STUDY

PROJECT MAX CAPACITY (MW)	SOLAR CAPACITY (MW)	TOTAL BATTERY (MW/% OF SOLAR)	REGION EXISTING SOLAR BEFORE ADDING COMBINED PLUS STORAGE PROJECT (MW)
500	500	50 (10%)	2,200
500	500	150 (30%)	2,200
500	500	250 (50%)	2,200
1,000	1,000	100 (10%)	3,200
1,000	1,000	300 (30%)	3,200
1,000	1,000	500 (50%)	3,200

Solar plus storage capacity value was analyzed with 2- and 4-hour battery storage representing 10%, 30%, and 50% of the nameplate solar MW. This evaluation was conducted with 500 and 1,000 MW of solar paired with storage out of 2,700 MW to 4,200 MW of total solar on the DEC system.

The ELCC of standalone storage was determined separately under the following two conditions:

- Economic Arbitrage – Assumes DEC maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.

- Fixed Dispatch – Assumes DEC has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEC did not have dispatch rights to the storage asset.

The following chart depicts the contribution to winter peak of solar plus storage under the two dispatch modes. The contribution to peak is the contribution of the solar MWs (i.e. a 100 MW solar facility with 25 MW of storage that provides 25% contribution to peak provides 25 MW towards meeting winter peak demand).

FIGURE H-7

AVERAGE CONTRIBUTION TO DEC WINTER PEAK OF SOLAR PLUS 2-HOUR DURATION STORAGE

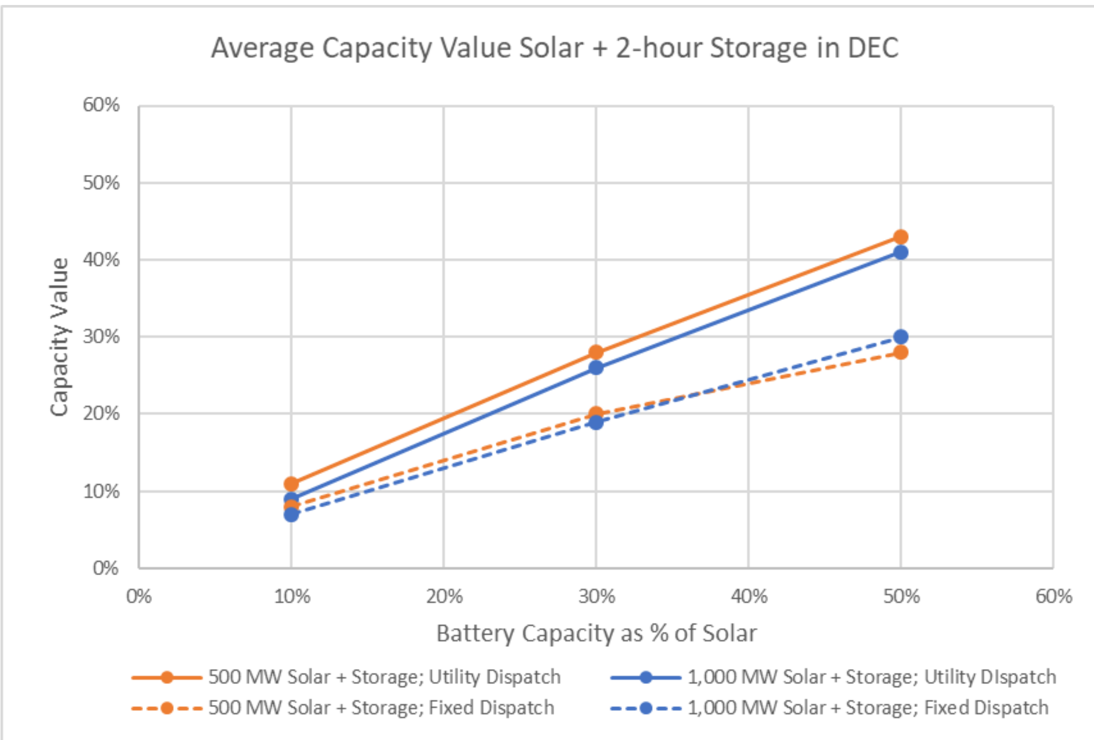

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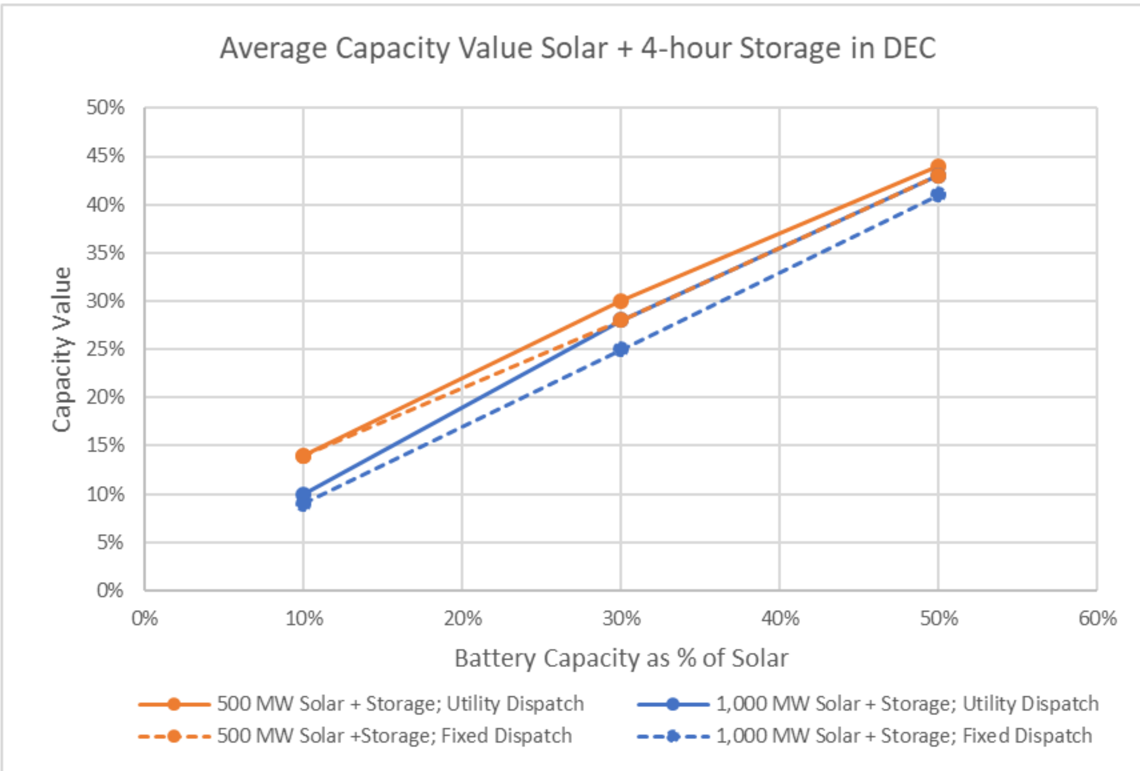
FIGURE H-8

AVERAGE CONTRIBUTION TO DEC WINTER PEAK OF SOLAR PLUS 4-HOUR DURATION STORAGE



Based on the results of the study, and for the same reasons as discussed in the standalone section above, DEC made the following assumptions in development of the 2020 IRP for solar plus storage:

- All solar plus storage capacity values based on Economic Dispatch. The Company will monitor how solar plus storage assets materialize on the system and will adjust this assumption in future IRPs if necessary
- Only 4-hour considered for storage paired with solar

Additionally, for solar paired with storage in DEC, the Company assumed that the capacity of storage was 25% of the nameplate capacity of the solar the storage was paired with. Based on the results of the ELCC study, the Company assumed that this solar plus storage provided 25% of the solar nameplate capacity towards meeting winter peak demand. Also, the solar plus storage projects were capped at the solar capacity, so a 400 MW solar facility paired with 100 MW of battery storage provided a maximum output of 400 MW and was ascribed 100 MW of capacity value.

CONSIDERATIONS FOR FUTURE STUDIES

For some of the portfolios presented in the IRP, specifically the No New Gas Portfolio (Pathway F), and to a lesser extent, the 70% carbon reduction portfolios (Pathways D and E), the level of solar plus storage exceeded the penetration of storage evaluated in the ELCC study. Additionally, in the no new gas portfolios, significant levels of standalone storage would likely deteriorate the capacity value of solar plus storage resources. The combination of standalone storage and solar plus storage was also not evaluated in the ELCC. In all cases, the contribution to winter peak for solar plus storage was assumed to equal the percentage of storage paired with solar. For these reasons, the contribution to winter peak demand of solar plus storage later in the planning horizon is likely overstated. Future storage ELCC studies should evaluate:

- Higher penetrations of solar plus storage
- The impacts of standalone storage on the value of solar plus storage

I

ENVIRONMENTAL COMPLIANCE

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APPENDIX I: ENVIRONMENTAL COMPLIANCE

Duke Energy Carolinas, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission, EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

AIR QUALITY

Duke Energy Carolinas is required to comply with numerous State and Federal air emission regulations, including the federal Acid Rain Program (ARP), the Cross-State Air Pollution Rule (CSAPR) NO_X and SO_2 cap-and-trade program, the Mercury and Air Toxics Standards (MATS) rule, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with these regulations, Duke Energy Carolinas reduced SO_2 emissions by approximately 96% from 2000 to 2019 and reduced NOx emissions by approximately 89% from 1997 to 2019. While the NC CSA was instrumental in achieving significant emission reductions to benefit air quality in North Carolina, recent federal regulations now impose more stringent requirements, as noted below.

The following is a summary of the major air related federal regulatory programs that are currently impacting, or that could impact, Duke Energy Carolinas operations in North Carolina.

CROSS-STATE AIR POLLUTION RULE (CSAPR)

The "good neighbor" provision of the Clean Air Act requires states in their State Implementation Plans (SIPs) to address interstate transport of air pollution that affects downwind states' ability to attain and maintain National Ambient Air Quality Standards (NAAQS). If states do not submit SIPs or EPA does not approve them, EPA must issue Federal Implementation Plans (FIPs) as a backstop. EPA has created several regulatory programs via the FIP process to address these emissions, including the Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule (CSAPR), and most recently, the CSAPR Update Rule. These programs establish state emission budgets for SO_2 and NOx on an annual basis, and NOx during ozone season (May 1-September 30.)

On September 7, 2016, EPA finalized the CSAPR Update Rule which reduces the ozone season NOx emission budgets from those promulgated in the original CSAPR Rule. The rule also removed North Carolina from CSAPR's ozone season NOx program beginning in 2017. However, Duke Energy units in North Carolina remain subject to annual NOx and SO_2 emission limits.

The Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court") recently decided environmental and industry challenges to the 2016 CSAPR Update Rule. The Court remanded the rule back to EPA for revision, and Duke expects EPA to issue a proposal addressing the Court's ruling by October 2020. However, EPA's determination that North Carolina sources should be excluded from the CSAPR Update Rule because they do not significantly contribute to downwind ozone non-attainment was not challenged and was not included in the remand from the D.C. Circuit Court.

MERCURY AND AIR TOXICS STANDARDS (MATS) RULE

On February 16, 2012, EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which established emission limits for hazardous air pollutants (HAP) from new and existing coal-fired and oil-fired steam electric generating units. The rule required sources to comply with emission limits by April 16, 2015, or by April 16, 2016 with an approved extension. Duke Energy Carolinas is complying with all rule requirements.

In June 2015, the Supreme Court determined that EPA had unreasonably refused to consider costs when it determined that it was appropriate and necessary to regulate hazardous air pollutants from coal-fired and oil-fired steam electric generating units and remanded the case to the D.C. Circuit Court for further proceedings.

On May 22, 2020, EPA published a final rule and concluded that it is not "appropriate and necessary" to regulate power plant HAP emissions. However, EPA declined to rescind the 2012 MATS rule. In addition, EPA issued the results of its statutorily required Residual Risk and Technology Review (RTR) and determined that no changes to the MATS emission standards are needed.

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS):

8-HOUR OZONE NAAQS:

In October 2015, EPA finalized revisions to the primary (health-based) and secondary (welfare-based) 8-Hour ozone national ambient air quality standard (NAAQS), lowering them from 75 to 70 parts per billion (ppb.) EPA finalized area designations for the 2015 ozone standard and did not designate any nonattainment areas in North Carolina.

In August 2019, the D.C. Circuit decided challenges from state, environmental, and industry challengers to the 2015 standard. The Court upheld the primary standard but remanded the secondary standard to EPA for "further explanation and reconsideration."

SO_2 NAAQS

On June 22, 2010, EPA finalized revisions to the sulfur dioxide (SO_2) NAAQS, establishing a 1-hour standard of 75 ppb. Based on review of ambient air quality monitoring data or modeled assessment of emission sources, EPA has designated each of the counties surrounding Duke Energy Carolinas facilities as attainment for the SO_2 NAAQS.

On March 8, 2019, after the periodic review required under the Clean Air Act, EPA issued a final rule retaining the SO_2 NAAQS standards, without revision.

FINE PARTICULATE MATTER ($PM_{2.5}$) NAAQS

On December 14, 2012, the EPA finalized revisions to the $PM_{2.5}$ ("fine particle") NAAQS, establishing an annual average standard of 12 micrograms per cubic meter and a 24-hour standard of 35 micrograms per cubic meter. The EPA finalized area designations for this standard in December 2014. That designation process did not result in any areas in North Carolina being designated nonattainment. On April 30, 2020, EPA proposed to retain the standards, without revision.

GREENHOUSE GAS REGULATION

On October 23, 2015, the EPA published a final rule establishing carbon dioxide (CO_2) emissions limits for new, modified and reconstructed power plants. The requirements for new plants apply to plants that commenced construction after January 8, 2014. EPA set an emission standard for new coal units of 1,400 pounds of CO_2 per gross MWh, which would require the application of partial carbon capture and storage (CCS) technology for a coal unit to be able to meet the limit. The EPA set a final standard of 1,000 pounds of CO_2 per gross MWh for new natural gas combined cycle (NGCC) units. Duke Energy Carolinas considers the standard for NGCC units to be achievable.

On December 20, 2018, EPA proposed revised NSPS standards. The proposed emission limit for new and reconstructed coal units is 1,900 pounds of CO_2/MWh, which is intended to reflect what has been demonstrated by the most efficient coal units without the use of CCS. The requirements apply to plants that commenced construction after December 20, 2018. EPA did not propose to change the standard established in 2015 for new or reconstructed natural gas combined-cycle units.

On October 23, 2015, the EPA published the Clean Power Plan (CPP) final rule, regulating CO_2 emissions from existing coal and natural gas units. The CPP established CO_2 emission rates and mass cap goals that apply to existing fossil fuel-fired EGUs. Petitions challenging the rule were filed by numerous groups, and on February 9, 2016, the Supreme Court issued a stay of the final CPP rule, halting its implementation.

On July 8, 2019, EPA finalized the Affordable Clean Energy (ACE) rule, and in a separate but related rule repealed the Clean Power Plan and established CO_2 emission standards for existing coal-fired power plants only. EPA declined to set standards for existing natural gas plants. States have until July 8, 2022, to submit plans based on application of efficiency improvements at existing coal-fired power plants to EPA for approval. Various environmental groups, states, and industry groups have filed petitions for review in the D.C. Circuit challenging the ACE rule, whereas many states and industry groups have intervened on behalf of EPA to defend the rule.

WATER QUALITY AND BY-PRODUCTS ISSUES

CWA 316(B) COOLING WATER INTAKE STRUCTURES

Federal regulations implementing §316(b) of the Clean Water Act (CWA) for existing facilities were published in the Federal Register on August 15, 2014, with an effective date of October 14, 2014. The rule regulates cooling water intake structures at existing facilities to address environmental impacts from fish being impinged (pinned against cooling water intake structures) and entrained (being drawn into cooling water systems and affected by heat, chemicals or physical stress). The final rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the United States. All DEC nuclear fueled, coal-fired and combined cycle stations in South Carolina and North Carolina are affected sources.

The rule establishes two standards, one for impingement and one for entrainment. To demonstrate compliance with the impingement standard, facilities must choose and implement one of the following options:

- Closed cycle re-circulating cooling system; or
- Demonstrate the maximum design through screen velocity is less than 0.5 feet per second (fps) under all conditions; or
- Demonstrate the actual through screen velocity, based on measurement, is less than 0.5 fps; or
- Install modified traveling water screens and optimize performance through a two-year study; or
- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality; or
- Demonstrate the impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

In addition to these options, the final rule allows the state permitting agency to establish less stringent

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standards if the capacity utilization rate is less than 8% averaged over a continuous 24-month period. The rule, also, allows the state permitting agency to determine no further action warranted if impingement is considered *de minimis*. Compliance with the impingement standard is not required until requirements for entrainment are established.

The entrainment standard does not mandate the installation of a technology but rather establishes a process for the state permitting agency to determine necessary controls, if any, required to reduce entrainment mortality on a site-specific basis. Facilities that withdraw greater than 125 MGD are required to submit information to characterize entrainment and assess the engineering feasibility, costs, and benefits of closed-cycle cooling, fine mesh screens and other technological and operational controls. The state permitting agency can determine no further action is required, or require the installation of fine mesh screens, or conversion to closed-cycle cooling.

The rule requires facilities to submit all necessary 316(b) reports in accordance with its Clean Water Act (CWA) discharge permit and schedule developed by the state permitting agency. Duke expects the state permitting authority to determine necessary controls for the affected DEC facilities in the 2020 to 2023 timeframe and intake modifications, if necessary, to be required in the 2022 to 2026 timeframe.

STEAM ELECTRIC EFFLUENT GUIDELINES

Federal regulations revising the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category ("ELG Rule") were published in the Federal Register on November 3, 2015, with an effective date of January 4, 2016. While the ELG Rule is applicable to all steam electric generating units, waste streams affected by these revisions are generated at DEC's existing coal-fired facilities. The revisions prohibit the discharge of bottom and fly ash transport water, and flue gas mercury control wastewater, and establish technology-based limits on the discharge of wastewater generated by Flue Gas Desulfurization (FGD) systems, and leachate from coal combustion residual (CCR) landfills and impoundments. The rule also establishes technology-based limits on gasification wastewater, but this waste stream is not generated at any of the DEC facilities. Affected facilities must comply between 2018 and 2023, depending on timing of its Clean Water Act (CWA) discharge permit.[1]

[1] On September 12, 2017, EPA finalized a rule ("the Postponement Rule") to postpone the earliest compliance date for bottom ash transport water and FGD wastewater for a period of two years (i.e. November 1, 2020), but this rule did not extend the latest compliance date of Dec. 31, 2023 and did not revise the earliest compliance date for fly ash transport water. The Postponement Rule was subsequently upheld by the Fifth Circuit Court of Appeals on August 28, 2019.

Petitions challenging the rule were filed by several groups and all challenges to the rule were consolidated in the Fifth Circuit Court of Appeals. On August 11, 2017, the EPA Administrator signed a letter announcing his decision to conduct a rulemaking to consider revising the new, more stringent effluent limitations and pretreatment standards for existing sources in the final rule that apply only to bottom ash transport water and FGD wastewater. On August 22, 2017, the Fifth Circuit Court of Appeals granted EPA's Motion to Govern Further Proceedings, thereby severing and suspending the claims related to flue gas desulfurization wastewater, bottom ash transport water and gasification wastewater. Subsequently, challenges to the limits for fly ash transport water and gasification wastewater were voluntarily dismissed while litigation on the limits for legacy wastewater and CCR leachate continued.

On April 12, 2019, the Fifth Circuit vacated and remanded portions of the rule dealing with legacy wastewater and CCR leachate. It is unknown when EPA will propose new limits for these waste streams.

The proposed rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater was published on November 22, 2019. The public comment period ended on January 21, 2020. The rule is anticipated to be finalized in 3rd quarter 2020.

All DEC coal-fired units have installed technologies to prohibit the discharge of fly ash transport water and to either eliminate the generation of bottom ash transport water or recirculate bottom ash transport water in a closed-loop system. Necessary upgrades or new FGD wastewater treatment systems have been installed at all affected DEC coal-fired units except for Rogers (Cliffside) Unit 5. Construction of the FGD wastewater treatment system at the Rogers (Cliffside) Unit 5 is in progress and expected to be completed by 4th quarter 2021. The anticipated final rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater is not expected to require the installation of any additional technology.

COAL COMBUSTION RESIDUALS

In January 2009, following Tennessee Valley Authority's Kingston ash pond dike failure, Congress issued a mandate to EPA to develop federal regulations for the disposal of coal combustion residuals (CCR). CCR includes fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. On April 17, 2015, EPA finalized the first federal regulations for the disposal of CCR. The 2015 CCR rule regulates CCR as a nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) and allows for beneficial use of CCR with some restrictions.

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The 2015 CCR rule applies to all new and existing landfills, new and existing surface impoundments that were still receiving CCR as of the effective date of the rule, and existing surface impoundments that were no longer receiving CCR but contained liquids as of the effective date of the rule, provided these units were located at stations generating electricity (regardless of fuel source) as of the effective date of the rule. The rule establishes national minimum criteria that include location restrictions, design standards, structural integrity criteria, groundwater monitoring and corrective action, closure and post-closure care requirements, and recordkeeping, reporting, and other operational procedures to ensure the safe management and disposal of CCR.

The 2015 CCR rule was challenged in litigation by industry and environmental petitioners. In August 2018, the D.C. Circuit Court vacated provisions that allowed unlined and clay-lined impoundments to continue to operate, finding those provisions violated the RCRA protectiveness standard. In response to the D.C. Circuit decision, EPA proposed two rulemakings to address unlined impoundments. The "Part A" rule, which was proposed on December 2, 2019, would establish an August 31, 2020 deadline to cease placement of CCR and non-CCR wastestreams into unlined ash basins and initiate closure (although that date is expected to be moved back in the final rule.)

The "Part B" rule, which was proposed on March 3, 2020, would establish a process for owners/operators to make an alternate liner demonstration. The proposal also included other significant provisions, including EPA's reiteration of its view that the use of CCR in units subject to forced closure is prohibited under the current CCR regulations. However, EPA proposed two options for allowing the use of CCR in surface impoundments and landfills for the purpose of supporting closure. In addition, EPA proposed a new closure-by-removal option, which would allow owners/operators to complete groundwater corrective action during the post-closure care period.

In February 2020, EPA published a proposed rule to establish a federal permitting program for CCR surface impoundments and landfills in states that do not have approved state permit programs, as provided under the 2016 WIIN Act. Only Oklahoma and Georgia currently have approved state programs, so this rule would apply in North Carolina until such a time that a state CCR permit program is approved by EPA.

In August 2019, EPA proposed amendments addressing CCR storage and criteria for unencapsulated beneficial uses that would require CCR storage piles to be completely enclosed (four walls and a roof), or would require control of releases and demonstration that the accumulation is "temporary" and that all CCR will be removed at some point in the future. EPA also proposed replacing the mass-based threshold for unencapsulated non-roadway beneficial uses to location-based criteria based on landfill location restrictions.

In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by North Carolina. On September 20, 2014, the North Carolina Coal Ash Management Act of 2014 (CAMA) became law and was amended on July 14, 2016.

CAMA establishes requirements regarding the beneficial use of CCR, the closure of existing CCR surface impoundments, the disposal of CCR at active coal plants, and the handling of surface and groundwater impacts from CCR surface impoundments. CAMA required eight “high-priority” CCR surface impoundments in North Carolina to be closed no later than December 31, 2019 (although that date was subsequently extended to August 1, 2022, for the two Asheville Station impoundments.) CAMA also required state regulators to provide risk-ranking classifications to determine the method and timing for closure of the remaining CCR surface impoundments. The North Carolina Department of Environmental Quality (NCDEQ) categorized all remaining CCR surface impoundments as low-risk after Duke Energy completed required dam safety repairs and established alternate permanent replacement water supplies for landowners with drinking water supply wells within a one-half-mile radius of CCR surface impoundments. Despite Duke Energy having taken these measures, on April 1, 2019, NCDEQ ordered that all remaining CCR surface impoundments in the state be closed by removal of CCR.

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NON-UTILITY GENERATION AND WHOLESALE

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APPENDIX J: NON-UTILITY GENERATION AND WHOLESALE

This appendix contains wholesale sales contracts, firm wholesale purchased power contracts and non-utility generation contracts.

TABLE J-1:

DEC AGGREGATED WHOLESALE SALES CONTRACTS

DEC AGGREGATED WHOLESALE SALES CONTRACTS								
WINTER COMMITMENT (MW)								
2020	2021	2022	2023	2024	2025	2026	2027	2028
2,146	2,076	2,028	2,044	2,061	2,078	2,093	2,107	2,124

NOTES:

- For wholesale contracts, Duke Energy Carolinas/Duke Energy Progress assumes all wholesale contracts will renew unless there is an indication that the contract will not be renewed.
- For the period that the wholesale load is undesignated, contract volumes are projected using the same methodology as was assumed in the original contract (e.g. econometric modeling, past volumes with weather normalization and growth rates, etc.).

TABLE J-2:

FIRM WHOLESALE PURCHASE POWER CONTRACTS

PURCHASED POWER CONTRACT	SUMMER CAPACITY (MW)	LOCATION	VOLUME OF PURCHASES (MWH)
			JUL 19-JUN 20
Peaking / Fuel Oil	21	NC	21,288
Peaking / Gas	91	NC/SC	463,408
Peaking / Hydro	11	GA/AL/SC	29,721
Base / Nuclear	51	NC	448,704
System	7	NC	43,068

NOTES: Data represented above represents contractual agreements. These resources may be modeled differently in the IRP.

NON-UTILITY GENERATION FACILITIES – NORTH CAROLINA

Please refer to DEC and DEP Small Generator Interconnection Consolidated Annual Reports filed on March 12, 2020 in NCUC Docket No. E-100, Sub 113B for details on the DEC North Carolina NUGS. The DEC NUG facilities are comprised of 99% intermediate facilities while the remaining 1% represents baseload facilities. Currently, hydro is considered baseload, solar and other renewables are considered intermediate.

Please refer to Table J-3 DEC Non-Utility Generator Listing – North Carolina Facilities.

NON-UTILITY GENERATION FACILITIES – SOUTH CAROLINA

Table J-4 contains non-utility generation contracts for facilities located in South Carolina.

Please refer to the attachment, Table J-4 DEC Non-Utility Generator Listing – South Carolina Facilities.

K

DEC QF INTERCONNECTION QUEUE

Corrected 11.06.2020

APPENDIX K: DEC QF INTERCONNECTION QUEUE

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition however the current queue clearly supports solar generation's central role in DEC's NC REPS compliance plan and HB 589.

Below is a summary of the interconnection queue as of July 31, 2020:

TABLE K-1
DEC QF INTERCONNECTION QUEUE

UTILITY	FACILITY STATE	ENERGY SOURCE TYPE	NUMBER OF PENDING PROJECTS	PENDING CAPACITY (MW AC)
DEC	NC	Battery	2	7
		Solar	95	2,365
	NC Total		97	2,372
	SC	Battery	2	14
		Hydroelectric	1	320
		Solar	138	2,676
	SC Total		141	3,010
	DEC Total		238	5,383

NOTE: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.

(2) Table does not include net metering interconnection requests.

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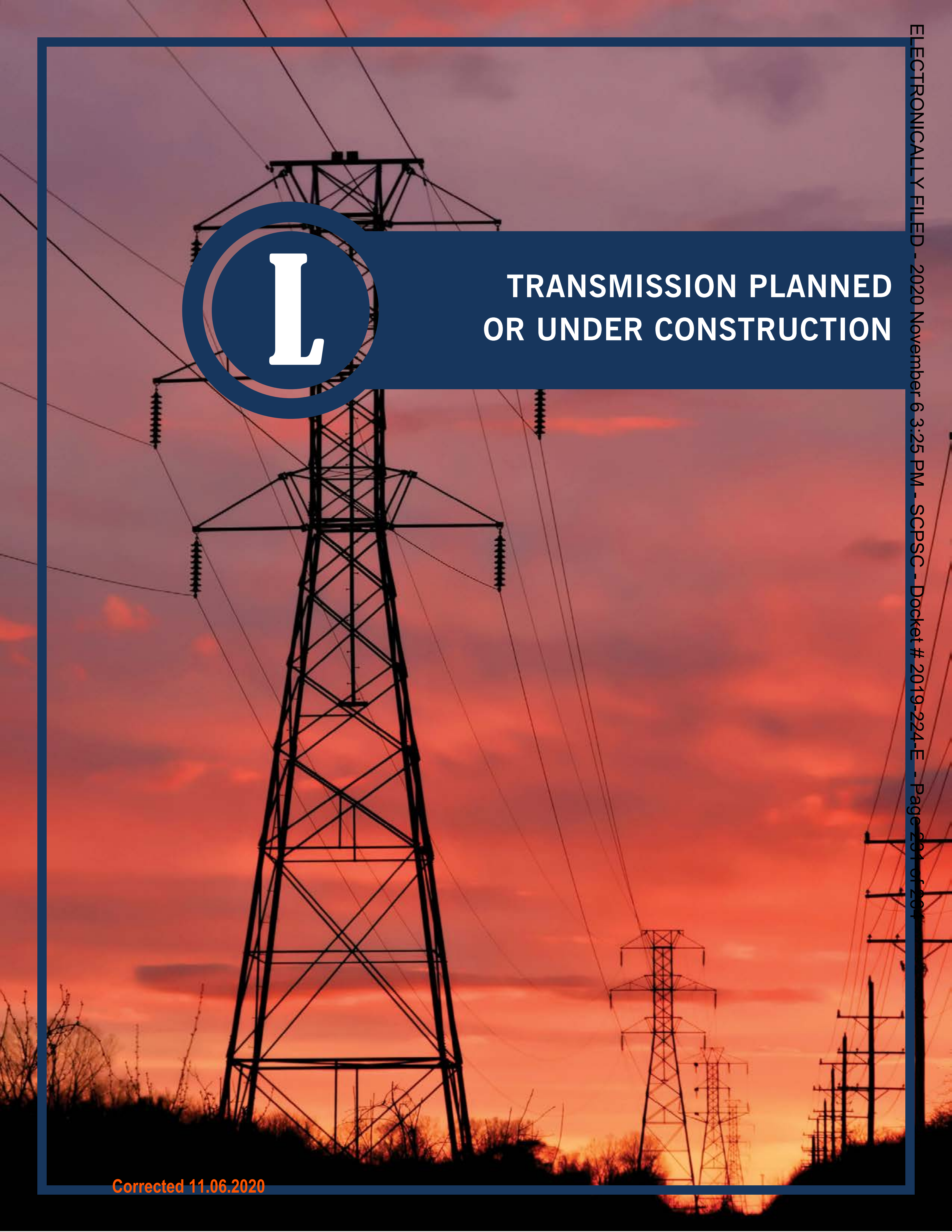

L

TRANSMISSION PLANNED OR UNDER CONSTRUCTION

Corrected 11.06.2020

APPENDIX L: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

In this section, DEC provide details on transmission projects planned or under construction, as well as how DEC ensures transmission system adequacy.

DEC IN-SERVICE TRANSMISSION

Table L-1 below reflects Duke Energy Carolinas installed transmission circuit miles at each voltage class.

TABLE L-1

DEC INSTALLED TRANSMISSION CIRCUIT MILES BY VOLTAGE CLASS

CIRCUIT VOLTAGE	44 KV	66-69 KV	100 - 199 KV	230 KV	345 KV	500+ KV
Duke Energy Carolinas	2,636	109	6,465	2,574		577

DEC TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This section lists the planned transmission line additions. A discussion of the adequacy of DEC's transmission system is also included. Table L-2 lists the transmission line projects planned to meet reliability needs. This section also provides other information pursuant to the North Carolina and South Carolina rules.

TABLE L-2

DEC TRANSMISSION LINE ADDITIONS

	LOCATION		CAPACITY	VOLTAGE	
YEAR	FROM	TO	MVA	KV	COMMENTS
None					

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CECPCN / CPCN

Certificates of environmental compatibility and public convenience and necessity (CECPCN) for the construction of electric transmission lines in South Carolina and Certificates of Public Convenience and Necessity (CPCN) in North Carolina

(p) Plans for the construction of transmission lines in North Carolina and South Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

Please refer to the Company's FERC Form No. 1 filed with FERC in April 2020.

(p) Plans for the construction of transmission lines in North Carolina and South Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) For lines under construction, the following:

- *a. Commission docket number;*
- *b. Location of end point(s);*
- *c. Length;*
- *d. Range of right-of-way width;*
- *e. Range of tower heights;*
- *f. Number of circuits;*
- *g. Operating voltage;*
- *h. Design capacity;*
- *i. Date construction started;*
- *j. Projected in-service date;*

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There are presently no new lines, 161 kV and above, planned for construction in DEC's service area.

DEC TRANSMISSION SYSTEM ADEQUACY

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at projected generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEC transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEC works with DEP, North Carolina Electric Membership Corporation (NCEMC) and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEC and DEP systems in both North and South Carolina. In addition, transmission planning coordinates with neighboring systems including Dominion Energy South Carolina Inc. (DESC; formerly SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between DESC, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEC's Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC Reliability Corporation (SERC) policy and North American Electric Reliability Corporation (NERC) Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure that there are no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at projected peak load with selected equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEC currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures in the OATT and related North Carolina and South

Carolina state procedures. It should be noted that location, MW interconnection requested, resource/load characteristics, and prior queued requests, in aggregate can have wide ranging impacts on transmission network upgrades required to reliably accommodate the interconnection request. In addition, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor and materials costs in future years could be significant.

SERC audits DEC every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEC to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEC in June 2019. The scope of this audit included standards impacting the Transmission Planning area. DEC received "No Findings" from the audit team in the areas associated with Transmission Planning activities.

DEC participates in several regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority area transfer capability and interconnection reliability. The reliability groups' reliability purposes are to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;

- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and

- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year future periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability. Application of the practices and procedures described above ensures that DEC's transmission system continues to provide reliable service to its native load and firm transmission customers.

ECONOMIC DEVELOPMENT

Corrected 11.06.2020

APPENDIX M: ECONOMIC DEVELOPMENT

CUSTOMERS SERVED UNDER ECONOMIC DEVELOPMENT

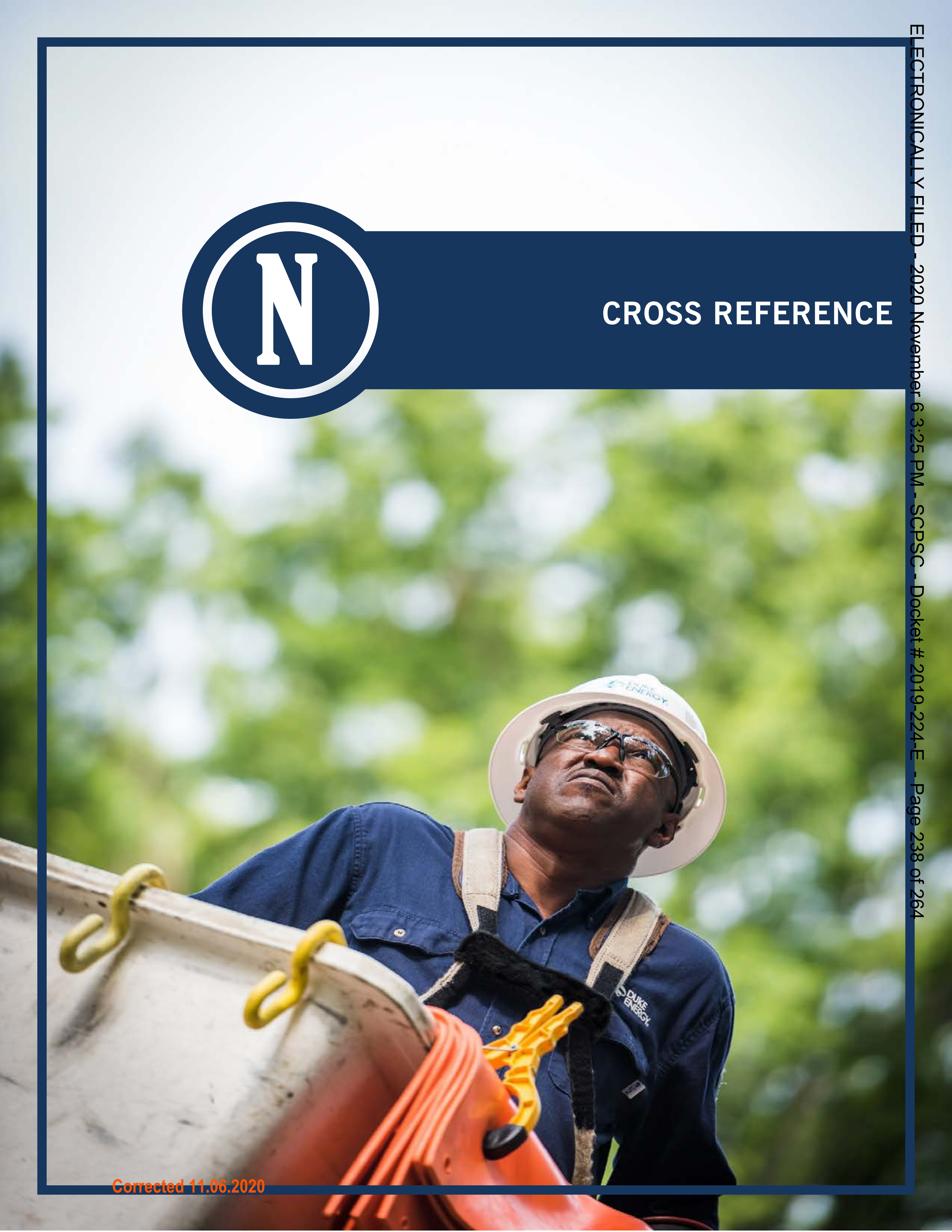
In the NCUC Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of June 2020 is:

RIDER EC

145 MW for North Carolina
131 MW for South Carolina

RIDER ER

41 MW for North Carolina
0 MW for South Carolina



N

CROSS REFERENCE

Corrected 11.06.2020

TABLE N-1

CROSS REFERENCE - NC R8-60 REQUIREMENTS

REQUIREMENT	REFERENCE	LOCATION
15-year Forecast of Load, Capacity and Reserves	NC R8-60 (c) 1	Chapter 3 Appendix C
Comprehensive analysis of all resource options	NC R8-60 (c) 2	Chapter 8 Chapter 12 Appendix A Appendix G
Assessment of Purchased Power	NC R8-60 (d)	Chapter 12 Appendix A Appendix J Attachment II
Assessment of Alternative Supply-Side Energy Resources	NC R8-60 (e)	Chapter 8 Appendix G
Assessment of Demand-Side Management	NC R8-60 (f)	Chapter 4 Appendix D Attachment V
Evaluation of Resource Options	NC R8-60 (g)	Chapter 5 Chapter 8 Appendix A Appendix D Appendix G
Short-Term Action Plan	NC R8-60 (h) 3	Chapter 14
REPS Compliance Plan	NC R8-60 (h) 4	Attachment I
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources * 10-year History of Customers and Energy Sales * 15-year Forecast w & w/o Energy Efficiency * Description of Supply-Side Resources	NC R8-60 (i) 1(i) NC R8-60 (i) 1(ii) NC R8-60 (i) 1(iii)	Chapter 3 Chapter 4 Appendix C Appendix D Attachment V

TABLE N-1
CROSS REFERENCE - NC R8-60 REQUIREMENTS (CONT.)

REQUIREMENT	REFERENCE	LOCATION
Generating Facilities * Existing Generation * Planned Generation * Non-Utility Generation	 NC R8-60 (i) 2(i) NC R8-60 (i) 2(ii) NC R8-60 (i) 2(iii)	 Chapter 2 Chapter 12 Appendix B Appendix J
Reserve Margins	NC R8-60 (i) 3	Chapter 9 Chapter 12 Attachment III
Wholesale Contracts for the Purchase and Sale of Power * Wholesale Purchased Power Contracts * Request for Proposal * Wholesale Power Sales Contracts	 NC R8-60 (i) 4(i) NC R8-60 (i) 4(ii) NC R8-60 (i) 4(iii)	Chapter 12 Chapter 14 Appendix A Appendix J
Transmission Facilities	NC R8-60 (i) 5	Chapter 7 Appendix L
Energy Efficiency and Demand-Side Management * Existing Programs * Future Programs * Rejected Programs * Consumer Education Programs	 NC R8-60 (i) 6(i) NC R8-60 (i) 6(ii) NC R8-60 (i) 4(iii) NC R8-60 (i) 4(iv)	Chapter 4 Appendix D Attachment V
Assessment of Alternative Supply-Side Energy Resources * Current and Future Alternative Supply-Side Resources * Rejected Alternative Supply-Side Resources	NC R8-60 (i) 7(i) NC R8-60 (i) 7(ii)	Chapter 8 Appendix A Appendix G
Evaluation of Resource Options (Quantitative Analysis)	NC R8-60 (i) 8	Appendix A
Levelized Bus-bar Costs	NC R8-60 (i) 9	Appendix G
Smart Grid Impacts	NC R8-60 (i) 10	Appendix D
Legislative and Regulatory Issues		Appendix I
Greenhouse Gas Reduction Compliance Plan		Chapter 16 Appendix A
Other Information (Economic Development)		Appendix M
NCUC Subsequent Orders		Table N-3

TABLE N-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each electrical utility must submit its integrated resource plan to the commission. The integrated resource plan must be posted on the electrical utility's website and on the commission's website.	Part (C)(2)	Post - filing
a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Part (C)(2)	Chapter 3 Appendix A Appendix C
The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	Part (C)(2)	Chapter 8 Appendix A Appendix F Appendix G
projected energy purchased or produced by the utility from a renewable energy resource;	Part (C)(2)	Chapter 5 Chapter 12 Appendix A Appendix E Appendix J Appendix N (DEP)
a summary of the electrical transmission investments planned by the utility;	Part (C)(2)	Chapter 7 Appendix A Appendix L

TABLE N-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i)customer energy efficiency and demand response programs; (ii)facility retirement assumptions; and (iii)sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	Part (C)(2)	Chapter 3 Chapter 4 Chapter 12 Appendix A Appendix B Appendix C Appendix D Appendix I
data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	Part (C)(2)	Chapter 2 Appendix B
plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan	Part (C)(2)	Chapter 7 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A

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TABLE N-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs	Part (C)(2)	Chapter 7 Chapter 8 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A Appendix G
a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	Part (C)(2)	Chapter 3 Chapter 4 Appendix C Appendix D
An integrated resource plan may include distribution resource plans or integrated system operation plans.	Part (C)(2)	Chapter 7 Chapter 11 Chapter 15 Appendix A Appendix L

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TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The two Base Case Plans (i.e. Base CO2 Future and Base No CO2 Future) … encourages the Companies to carry forward both alternatives for their next IRPs due for 2020.”	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 12 Appendix A
DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company’s existing coal-fired generating units are retired by the earliest practicable date. The “earliest practicable date” shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified. In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A Appendix I

DUKE ENERGY CAROLINAS

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Commission expects that the "earliest practicable date" chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. The Companies should also attempt to identify – with as much specificity as is possible in the circumstances - all major transmission and distribution upgrades that will be required to support the alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 7 Chapter 11 Appendix A Appendix L
The Companies should note that the directive in this order supplements and does not supersede the directive in the Commission's August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles. In this Order the Commission's directive that the Companies present one or more "earliest practicable date" retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20 E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Updated resource adequacy studies be filed along with the Companies' 2020 IRPs, together with all supporting exhibits, attachments and appendices subject to such confidentiality designations as the Companies deem warranted.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	IRP Filing Letters Chapter 9 Attachment III
In documenting the updated Resource Adequacy Study for 2020, the Companies should provide additional detail and support for both the study inputs and outputs.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission will direct DEC and DEP to more fully explain and detail the study results.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The updated Resource Adequacy Study should provide additional clarity around outputs… At a minimum the Commission finds it helpful for results to be displayed in a graphic that clearly shows the various components to the Total System Costs such as included in the "Bathtub Curves."	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission directs the updated Resource Adequacy studies to address the sensitivity of modeling inputs such as Equivalent Forced Outage Rates (EFOR).	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III

DUKE ENERGY CAROLINAS

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Companies to continue to involve stakeholders in a meaningful way as the ISOP process advances. In particular, the Commission recognizes that there could be significant benefits to involving North Carolina's electric membership cooperatives and municipally owned and operated electric utilities in this effort.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Executive Summary Chapter 15
The 2020 IRPs should continue to report on the progress of the ISOP effort. As a minimum, the IRPs should communicate with some specificity the project plan and dates for the ISOP effort. In addition, the Commission will direct the utilities to discuss the expected outputs of the ISOP process and how they will be utilized in the IRP process.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 15
The Commission determines that the "First Resource Need" section of DEC's and DEP's 2019 IRPs is an appropriate output of the integrated resource planning processes and adequate to support future avoided cost calculations.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 13
Demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 3 Chapter 4 Chapter 8 Chapter 12 Appendix A Appendix D Appendix G Appendix J

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 12 Chapter 14 Appendix A Appendix J
A discussion of the following statement: "The Companies' analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a quantitative analysis of the resource options available to meet customers' future energy needs. This analysis intended to produce a base case through a least cost analysis where each company's system was optimized independently. However, the modeling exercise fails to consider whether existing resources can be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans."	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Chapter 12 Chapter 16 Appendix A
(d) A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC's and DEP's Portfolio 5 in their 2018 IRPs.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Appendix A Appendix D

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Provide a discussion of the advantages and disadvantages of periodically issuing "all resources" RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Include information, analyses, and modeling regarding economic retirement of coal-fired units	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Model continued operation under least cost principles in competition with alternative new resources	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A

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TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
If continued operation until fully depreciated is least cost alternative, shall separately model an alternative scenario premised on advanced retirement of one or more of such units (including an analysis of the difference in cost from the base case and preferred case scenarios.)	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 4	Chapter 9 Attachment III
Future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 5	Filed Under Seal
IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 7	Appendix D

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TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 8 E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 9	Appendix D Attachment V
All IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.	E-100, Sub 141, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/26/15, ordering paragraph 9 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 9 E-100, Sub 133, Order Denying Rulemaking Petition (Allocation Methods), dated 10/30/12, ordering paragraph 4	Chapter 3 Appendix C

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 14 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 14	Chapter 5 Appendix E Appendix K
Duke plans to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of customers, pursue second license renewal.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 7) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 10

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TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Duke will include Li-ion battery storage technology in the economic supply-side screening process as part of the IRP.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 19) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 6 Chapter 8 Chapter 12 Appendix A Appendix G Appendix H
DEP will incorporate into future IRPs any demand and energy savings resulting from the Energy Efficiency Education Program, My Home Energy Report Program, Multi-Family Energy Efficiency Program, Small Business Energy Saver Program, and Residential New Construction Program.	E-2, Sub 1060, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 989, Order Approving Program, dated 12/18/14, p. 3 E-2, Sub 1059, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 1022, Order Approving Program, dated 11/5/12, footnote 2 (Small Business Energy Saver) E-2, Sub 1021, Order Approving Program, dated 10/2/12, footnote 3 (Residential New Construction Program)	Appendix D

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TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 16	Chapter 8 Appendix A Appendix F Appendix G
DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 15	Chapter 5 Appendix A Appendix E Appendix N (DEP)
DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret.	E-100, Sub 137, Order Granting in Part and Denying in Part Motion for Disclosure, dated 6/3/13, ordering paragraph 3	Attachment I

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
[2013] Duke shall show the peak demand and energy savings impacts of each measure/option in the Program separately from each other, and separately from the impacts of its other existing PowerShare DSM program options in its future IRP and DSM filings, and in its evaluation, measurement, and verification reports for each measure of the Program.	E-7, Sub 953, Order Approving Amended Program, dated 1/24/13, ordering paragraph 4 (PowerShare Call Option Nonresidential Load and Curtailment Program)	Appendix D
Each utility shall include in each biennial report potential impacts of smart grid technology on resource planning and load forecasting: a present and five-year outlook – see R8-60(i)(10).	E-100, Sub 126, Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1, dated 4/11/12	Chapter 14 Appendix D

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GLOSSARY OF TERMS

10 CFR	Title 10 of the Code of Federal Regulations
AC or A/C	Alternating Current
ACE	Affordable Clean Energy
ACP	Atlantic Coast Pipeline
ACT 62	South Carolina Act 62
ADP	Advanced Distribution Planning
AEO	Annual Energy Outlook
AGC	Automatic Generator Control
AMI	Advanced Metering Infrastructure
APS	Arizona Public Service Electric
ARP	Acid Rain Program
ARPA-E	Advanced Resource Projects Agency-Energy
ASOS	National Weather Service Automated Surface Observing System
BHPCC	Blue Horizons Project Community Council (DEP)
BCFD	Billion Cubic Feet Per Day
BFB	Bubbling Fluidized Bed
BOEM	Bureau of Ocean Energy Management
BYOT	Bring Your Own Thermostat
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMA	North Carolina Coal Ash Management Act of 2014
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CCR	Coal Combustion Residuals Rule
CCS	Carbon Capture and Sequestration (Carbon Capture and Storage)
CCUS	Carbon Capture, Utilization and Storage
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity (SC)
CEP	Comprehensive Energy Planning
CES	Clean Electricity Standard
CFL	Compact Fluorescent Light bulbs
CHP	Combined Heat and Power

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GLOSSARY OF TERMS (CONT.)

CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COVID-19	Coronavirus 2019
COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity (NC)
CPP	Clean Power Plan
CPRE	Competitive Procurement of Renewable Energy
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DC	Direct Current
DCA	Design Certification Application
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEI	Duke Energy Indiana
DEK	Duke Energy Kentucky
DEP	Duke Energy Progress
DER	Distributed Energy Resource
DER	Duke Energy Renewables
DESC	Dominion Energy South Carolina, Inc. (formerly SCE&G)
DIY	Do It Yourself
DMS	Distribution Management System
DoD	Depth of Discharge
DOE	Department of Energy
DOJ	Department of Justice
DOM	Dominion Zone within PJM RTO
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSDR	Distribution System Demand Response Program
DSM	Demand-Side Management

GLOSSARY OF TERMS (CONT.)

EC or Rider EC	Receiving Credits under Economic Development Rates and/or Self-Generation deferral rate
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration
EITF	Energy Innovation Task Force
ELCC	Effective Load Carrying Capability
ELG Rule	Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction Contractors
EPRI	Electric Power Research Institute
ER or Rider ER	Receiving Credits under Economic Re-Development Rates
ESG	Environmental, Social and Corporate Governance
ET	Electric Transportation
EVs	Electric Vehicles
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLG	Federal Loan Guarantee
FPS	Feet Per Second
FRCC	Florida Reliability Coordinating Council, Inc.
FSO	Fuels and System Optimization
FT Solar	Fixed-tilt Solar
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GA-AL-SC	Georgia-Alabama-South Carolina
GHG	Greenhouse Gas
GIP	Grid Improvement Plan
GTI	Gas Technology Institute
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HB 589	North Carolina House Bill 589
HRSG	Heat Recovery Steam Generator

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GLOSSARY OF TERMS (CONT.)

HVAC	Heating, Ventilation and Air Conditioning
IA	Interconnection Agreement
IESO	Independent Electricity System Operator
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
ILR	Inverter Load Ratios
IPI	Industrial Production Index
IRP	Integrated Resource Plan
IS	Interruptible Service
ISO-NE	ISO New England, Inc.
ISOP	Integrated Systems and Operations Planning
IT	Information Technologies
ITC	Federal Investment Tax Credit
IVVC	Integrated Volt-Var Control
JDA	Joint Dispatch Agreement
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized Cost of Energy
LCR Table	Load, Capacity, and Reserves Table
LED	Light Emitting Diodes
LEED	Leadership in Energy and Environmental Design
LEO	Legally Enforceable Obligation
LFE	Load Forecast Error
Li-ION	Lithium Ion
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
M&V	Measurement and Verification
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MGD	Million Gallons Per Day
MISO	Midcontinent Independent Operator

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GLOSSARY OF TERMS (CONT.)

MPS	Market Potential Study
MMBtu	Million British Thermal Units
MW	Megawatt
MW AC	Megawatt-Alternating Current
MW DC	Megawatt-Direct Current
MWh	Megawatt-hour
MWh AC	Megawatt-hour-Alternating Current
MWh DC	Megawatt-hour-Direct Current
MyHER	My Home Energy Report
NAAQS	National Ambient Air Quality Standards
NAPP	Northern Appalachian Coal
NC	North Carolina
NC HB 589	North Carolina House Bill 589
NC REPS or REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCCSA	North Carolina Clean Smokestacks Act
NCDAQ	North Carolina Division of Air Quality
NCDEQ	North Carolina Division of Environmental Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission
NEM	Net Energy Metering
NEMS	National Energy Modeling Systems
NERC	North American Electric Reliability Corporation
NERC RAPA	Reliability and Performance Analysis
NES	Neighborhood Energy Saver
NESHAP	National Emission Standards for Hazardous Air Pollutants
NET CONE	Net Cost of New Entry
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System

GLOSSARY OF TERMS (CONT.)

NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
NUG	Non-Utility Generator
NUREG	Nuclear Regulatory Commission Regulation
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance
OATT	Open Access Transmission Tariff
PC	Participant Cost Test
PD	Power Delivery
PERFORM	Performance-based Energy Resource Feedback, Optimization and Risk Management
PEV	Plug-In Electric Vehicles
PHS	Pumped Hydro Storage
PJM	PJM Interconnection, LLC
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PRB	Powder River Basin
PROSYM	Production Cost Model
PSCSC	Public Service Commission of South Carolina
PSD	Prevention of Significant Deterioration
PSH	Pumped Storage Hydro
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PVDG	Solar Photovoltaic Distributed Generation Program
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificate
REPS or NC REPS	Renewable Energy and Energy Efficiency Portfolio Standard

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GLOSSARY OF TERMS (CONT.)

RFP	Request for Proposal
RICE	Reciprocating Internal Combustion Engines
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
RRP	Refrigerator Replacement Program
RTO	Regional Transmission Organization
RTR	Residential Risk and Technology Review
SAE	Statistical Adjusted End-Use Model
SAT Solar	Single-Axis Tracking Solar
SB 3 or NC SB 3	North Carolina Senate Bill 3
SC	South Carolina
SC Act 62	South Carolina Energy Freedom Act of 2018
SC DER or SC ACT 236	South Carolina Distributed Energy Resource Program
SC DER	South Carolina Distributed Energy Resources
SCR	Selective Catalytic Reduction
SEER	Seasonal Energy Efficiency Ratio
SEIA	Solar Energy Industries Association
SEPA (Ch. 15)	Smart Electric Power Alliance
SEPA (Ch. 2)	Southeastern Power Administration
SERC	SERC Reliability Corporation
SERVM	Strategic Energy Risk Valuation Model
SG	Standby Generation or Standby Generator Control
SIP	State Implementation Plan
SISC	Solar Integration Services Charge
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
SO	System Optimizer
SO2	Sulfur Dioxide
SOC	State of Charge
SOG	Self-Optimizing Grid
SPM	Sequential Peaker Method

GLOSSARY OF TERMS (CONT.)

SRP – SLR	Standard Review Plan for the Review of Subsequent License Renewal
STAP	Short-Term Action Plan
STEO	Short-Term Energy Outlook
SVC	Static Var Compressors
T&D	Transmission & Distribution
TAG	Technology Assessment Guide
TCFD	Trillion Cubic Feet per Day
Transco	Transcontinental Pipeline
The Company	Duke Energy Progress
The Plan	Duke Energy Progress Annual Plan
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCT	Utility Cost Test
UEE	Utility Energy Efficiency
UNC	University of North Carolina
USCPC	Ultra-Supercritical Pulverized Coal
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive
VCEA	Virginia Clean Economy Act
VVO	Volt-Var Optimization
WCMP	Western Carolinas Modernization Project (DEP)
WERP	Weatherization and Equipment Replacement Program
WIIN	Water Infrastructure Improvement for the Nation Act
ZELFR	Zero – Emitting Load Following Resource

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